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Industrial Environmental Research Lab, Research Triangle Park, N C

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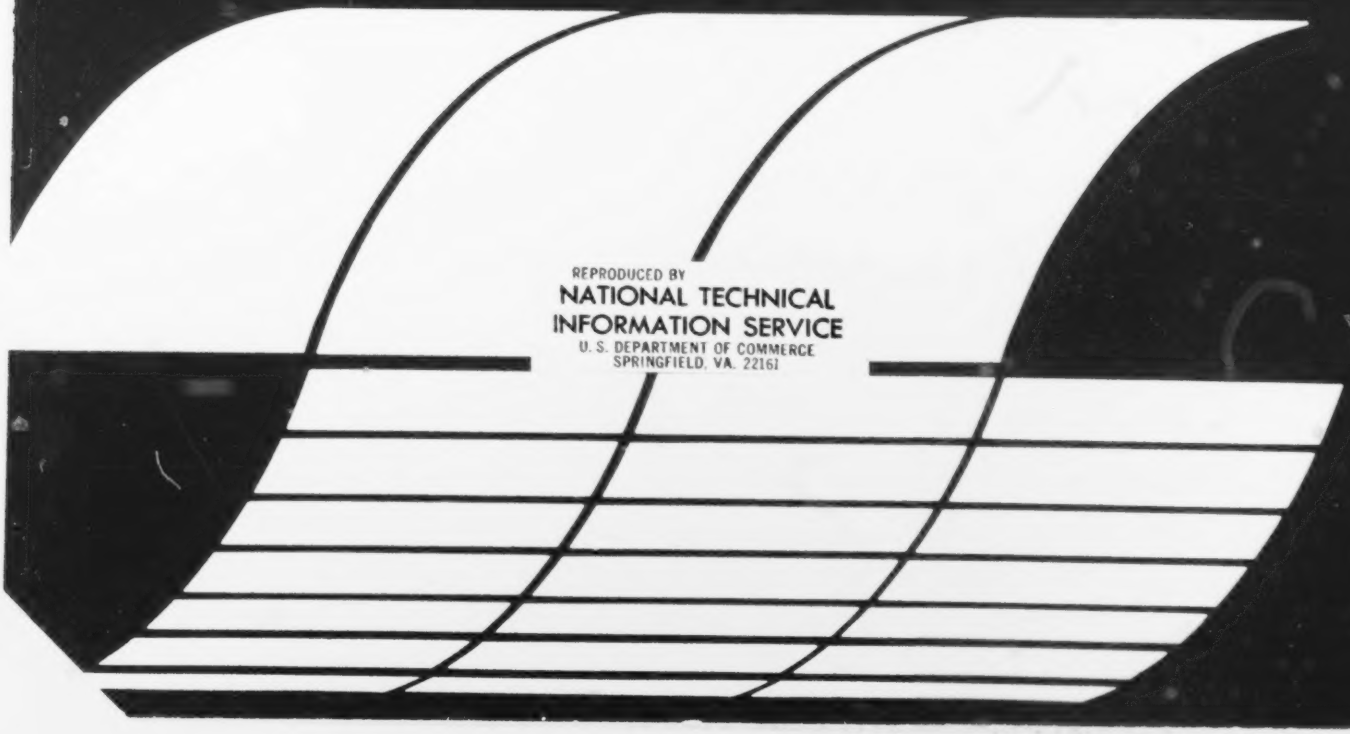
November 1977

UTILITY BOILER DESIGN/COST COMPARISON: FLUIDIZED-BED COMBUSTION VERSUS FLUE GAS DESULFURIZATION

Interagency Energy-Environment Research and Development Program Report



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16. ABSTRACT

The report gives results of a conceptual design, performance, and cost comparison of utility scale (750-925 MWe) coal-burning power plants employing three alternative technologies: conventional boiler with a stack gas scrubber (CWS), atmospheric-pressure fluidized-bed combustion (AFB), and pressurized fluidized-bed combustion/combined cycle (PFB). The AFB and PFB designs/estimates used were completed by the General Electric Co. as part of the Energy Conversion Alternatives Study (ECAS), funded by NASA, ERDA, and NSF. The CWS designs/estimates were developed by GE for this study, using the same basis as for the ECAS. TVA modified the GE results to: reflect TVA costing experience, consider alternate wet scrubbing techniques for the CWS, and include comparable solid waste disposal costs for all three plants, considering alternative disposal options. Results suggest that AFB offers a possible savings of 9-14% in the cost of electricity (COE) in comparison with CWS, and PFB offers a savings of up to 7%. The estimated COE for the three alternatives is so close that all are considered to be within the competitive range for further consideration.

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UTILITY BOILER DESIGN/COST COMPARISON: FLUIDIZED-BED COMBUSTION VERSUS FLUE GAS DESULFURIZATION

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ABSTRACT

A conceptual design, performance and cost comparison was completed for utility-scale (750-925 MWe) coal-burning power plants employing three alternative technologies: (1) conventional boiler with a stack gas scrubber (CWS); (2) atmospheric-pressure fluidized-bed combustion (AFB); and (3) pressurized fluidized-bed combustion; combined cycle (PFB). The AFB and PFB designs; estimates used were those completed by the General Electric Company team as part of the Energy Conversion Alternatives Study (ECAS), funded by NASA, ERDA and NSF. The CWS designs/estimates were developed by the GE team for the study reported here, using the same basis as was used for ECAS. TVA modified and expanded the GE results to: (1) reflect TVA costing experience and include an uncertainty allowance for undemonstrated technology; (2) consider alternate wet scrubbing techniques for the CWS, including lime scrubbing, limestone scrubbing and magnesium oxide scrubbing; and (3) include solid waste disposal costs for all three plants for a 30-year lifetime, and assess alternative disposal options. The results suggest that: (1) AFB offers a possible savings of 9 to 14 percent in the cost of electricity (COE) in comparison with CWS, and PFB offers a savings of 0 to 7 percent, depending on whether or not an uncertainty allowance is applied; (2) hot gas cleaning and pressurized solids handling in the PFB are major contributors to the COE (the cost of these items can vary significantly if different design conditions are assumed), offsetting the savings resulting from PFB's greater energy efficiency; and (3) application of alternate scrubbing techniques does not affect the economics of CWS enough to significantly change its position relative to AFB AND PFB. When uncertainties are included, the estimated COE for the three alternatives is so close that all are considered to be within the competitive range for further consideration.

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CONVERSION TABLE

EPA policy is to express all measurements in Agency documents in metric units. When implementing this policy results in undue cost or difficulty in clarity, the Industrial Environmental Research Laboratory-Research Triangle Park (IERL-RTP) provides conversion factors for the particular nonmetric units used in the document. For this report these factors are:

British		Metric
Multiply	By	To Obtain
feet	3.0480×10^{-1}	meters
feet^2	9.29×10^{-2}	meters^2
feet/sec.	3.0480×10^{-1}	feet/sec.
feet^3/min.	4.720×10^{-1}	liters/sec.
gallon	3.785	liters
inch	2.5400×10^{-2}	meters
micron	1.0×10^{-6}	meters
ounce (troy)	3.1103×10^{1}	grams
pound	4.536×10^{-1}	kilograms
pound/in.^{2}	7.03×10^{-2}	kg/cm^2
quart	9.463×10^{-1}	liters
tons/hr.	2.520×10^{-1}	kg/sec.

Temperature Conversion - Farenheit (°F) to Kelvin (°K)

$$\text{Temperature } (^\circ\text{K}) = \frac{5}{9}(T_f - 32^\circ) + 273^\circ$$

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(a) General Electric Company

Electric Utility Systems Engineering Department
Corporate Research and Development
Large Steam Turbine - Generator Department
Technical Resources Planning, Turbine Operations
Technical Resources Staff

(b) Bechtel Corporation

(c) Foster Wheeler Energy Corporation

This effort utilized fluidized bed combustion power plant designs developed in Phase II of the Energy Conversion Alternatives Study (ECAS) (Ref. 5). The conventional plant information was developed by the GE team under NASA contract NAS 3-19406 on a basis consistent with the ECAS Phase II effort.

The Environmental Protection Agency (EPA) provided funding for the GE conventional plant effort and for additional work by TVA under TV-41967A and interagency agreement EPA-IAG-D5-E721.

INTRODUCTION

The increasing demand for electrical power coupled with the growing concern for environmental effects of coal-fired power plants create a special problem in the utility industry.

The goal of near-term energy independence requires that new fossil-fired plants utilize our Nation'a vast coal resources. The majority of our coal, however, is unsuitable as a conventional power plant fuel. High sulfur oxide emissions from coal-fired plants have been evaluated as environmentally unaceptable. Limitations on these emissions have been imposed requiring either removal of coal sulfur before burning or reduction of sulfuric oxide concentration in the stack gas. Much of the coal is unsuitable for economic sulfur removal by conventional methods. Utilizing high sulfur coals in conventional coal-fired plants requires stack gas cleanup. The only existing technology for adequate sulfur oxide reduction is wet scrubbing.

Wet scrubbers are expensive, however, and have posed some operational problems. A near term alternative to conventional/wet scrubber power plants (CWS) is fluidized bed combustion power plants. Atmospheric fluidized bed combustion power plants (AFB) are basically similar to conventional power plants with the substitution of fluidized bed modules for the conventional steam generator. Pressurized fluidized bed power plants (PFB) add an extra dimension through utilization of a coal-fired gas turbine.

The U.S. Environmental Protection Agency (EPA) recognized the need to evaluate the economics of near term alternatives to conventional/wet scrubber plants. TVA, at the request of EPA, undertook the assignment of comparing the costs of fluidized bed combustion power plants (AFB and PFB) to the costs of conventional/wet scrubber plants (CWS). In an effort to accomplish this economically and expeditiously, information developed in the Energy Conversion Alternatives Study (ECAS) was utilized as a data base.

ECAS has studied viable concepts for advanced power plants fired by coal or coal-derived fuel. This effort combined resources of three U.S. agencies, National Science Foundation, Energy Research and Development Administration, and National Aeronautics and Space Administration (NSF, ERDA, and NASA), and the contracted expertise and experience of contractor teams led by the General Electric Company (GE) and the Westinghouse Electric Company.

ECAS included three primary tasks: parametric analysis (Task 1), conceptual design and cost estimation (Task 2), and implementation assessment Task 3). In Task 1, ten categories of power plant were analyzed parametrically. On the basis of the results from that analyses, 11 specific advanced plant types were selected for the Task 2 and Task 3 effort. GE was responsible for seven of these including atmospheric fluidized bed combustion (AFB) and pressurized fluidized bed combustion (PFB) power plants. The GE portion of the ECAS work was done by a GE Corporate Research and Development team which included the Foster Wheeler Energy Corporation and the Bechtel Corporation. In order to facilitate a cost comparison of fluidized bed combustion to conventional pulverized coal-fired power plants utilizing wet stack gas scrubbers (CWS) it was necessary to develop comparative conceptual designs and cost estimates for the conventional plant.

EPA provided the funding necessary for this additional CWS plant study which was performed on the same design and economic premises as the ECAS study.

Included in the GE study results used in this report are the following items:

1. Study ground rules
2. Conventional/wet scrubber power plant (CWS) design (lime scrubber)
3. Atmospheric fluidized bed power plant (AFB) design
4. Pressurized fluidized bed power plant (PFB) design
5. Balance of plant equipment necessary for the CWS, AFB, and PFB plants
6. Operating and maintenance costs for the CWS, AFB, and PFB plants
7. Comparison of alternatives

The conceptual designs and cost estimates developed by the GE team provide cost data based on common ground rules for the CWS, AFB, and PFB systems. All three systems were assumed to be developed to a commercially available state of art and received common treatment in the generation of design and cost information. TVA feels that although the GE effort was guided by a consistent evaluation basis, there are areas where modification would provide a more comprehensive and utility representative study.

The capital and operating costs obtained by GE for the CWS, AFB and PFB were modified by TVA to take into consideration a number of factors felt to be significant. Three major factors were addressed:

1. Modification of the estimates to include an uncertainty allowance for those plant components not felt to be demonstrated technology; and modification of the GE estimates for various components where such revision is felt to be warranted based upon TVA design experience.

2. Expansion of the GE estimates to take into consideration:

    a. Adequate provisions for residue disposal over the full 30-year plant lifetime, for all cases (previously GE included only 5-year disposal provisions for the CWS case, and none for AFB and PFB).

    b. Alternate disposal options.

The TVA estimates are only modifications of the GE cost figures and should not be construed as an estimate of costs for which TVA believes these plants could be constructed for today.

EXECUTIVE SUMMARY

A. SCOPE

This report presents the results from a study that has been conducted to compare the economic and performance characteristics of three power plants, each of which generates electricity at approximately the same net capacity and each of which employs a different scheme for controlling the emissions of air polluting constituents in its flue gases. The difference between the three plants are essentially identified by the type of steam generator and the associated provision for removal of sulfur dioxide from the products of combustion. The three plants are designated as follows:

1. Conventional pulverized coal-fired steam plant with stack gas scrubber (CWS);
2. Atmospheric fluidized bed combustion power plant (AFB);
3. Pressurized fluidized bed combustion power plant (PFB).

The evaluation of the CWS was performed for two values of gas temperature, namely, 250 F and 175 F to which the combustion gases were reheated after leaving the wet gas scrubbers and prior to entering the stack. Also included for comparison was the condition that assumed low sulfur coal was burned and the scrubber system eliminated from the plant.

The study of the PFB plant included consideration of main bed operating temperature of 1650 F and 1750 F and an alternate high-efficiency cycle for the 1750 F case that utilized a high temperature feedwater heater in addition to those provided in the base cycle of the PFB plant.

As an extension of the performance and economic analyses performed for the plants and conditions described above, several alternate scrubbing systems were analyzed as were various schemes for disposal of scrubber sludge from the CWS and disposal of solid waste from the fluidized bed plants.

B. COMMON SYSTEM PARAMETERS

As nearly as was feasible, the basic system parameters in each of the three power plants were taken to be the same. Likewise, the provisions for onsite storage and handling of fuel and sorbent as well as requirements for the balance-of-plant components were maintained as similar as was practical for the three

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plants. Consistent ground ruler and costing methodology were applied in evaluating the plants. Table 1 is a list of design parameters common to the three plants.

C. ECONOMIC EVALUATION CRITERIA

The economic and performance evaluations for the study were first carried out by the General Electric Company (GE) and then the results and studies were modified/extended by TVA to more realistically reflect utility practice and account for the uncertainties inherent in systems undergoing various stages of technological development.

The evaluations for each power plant conducted by GE were performed using the methodology and criteria consistent with that used in the Energy Conversion Alternatives Study (ECAS). Each of the three types of plants was assumed to be developed to a commercially available state-of-the-art and no consideration was given to developmental costs.

A lime slurry scrubber with onsite calcination and provisions for a five-year storage of sludge was assumed for the CWS studies performed by GE. The AFB and PFB plants were assumed by GE to have provisions for hauling of the solid wastes to an offsite location. The costs for disposing of the solid wastes from the AFB and PFB plants were not included by GE.

TVA's modification of the results by General Electric included the following:

1. Revision of some items in GE's cost estimates to more reasonably reflect current utility practice;

2. Application of an uncertainty allowance to the cost of those items of equipment in which uncertainties of design and scale up of components were not accounted for in the GE studies. These uncertainty allowances do not take into account costs to develop the components or to start up the process.

The previously mentioned extension of the study to include investigation of additional scrubber systems and alternative methods of disposing of sludge and solid wastes was also performed by TVA. The alternative methods of scrubbing considered by TVA were lime w/onsite calcination, lime w/offsite calcination, limestone, and regenerable magnesium oxide. Estimates for 30-year disposal were made for each scrubbing alternative as well as for the AFB and PFB plants.

D. RESULTS

1. Comparison of Results Prepared by GE

A comparison of performance and corresponding cost of electricity for the several plants and alternatives considered is presented in Table 107 which is reproduced here for convenience. The entries are arranged in Table 107 in decreasing order of overall efficiency.

TABLE 1

Key Design Parameters

Fuel

Illinois No. 6 Coal
Cost: $1.00/10^6 Btu
HHV: 10,788 Btu/lb
3.9% Sulfur
9.6% Ash

Steam Conditions

3515 psia inlet pressure
1000°F inlet temperature
1000°F reheat temperature

Heat Rejection

Mechanical draft cooling towers
Ambient Air Temperatures: 59° dry bulb, 51.5°F wet bulb

Economic Factors

Base Load Plant (capacity factor = 65 percent)
30 year plant lifetime
90 percent availability
Cost basis: Mid-1975$
Interest during construction: 10% per year
Escalation during construction: 6.5% per year
Fixed charge rate: 18% per year
Construction time: 5.5 years
Sorbent cost: $5.00/ton

Plant Capacity

747 - 923 MW_e

Table 107

EFFICIENCY ORDER OF STEAM PLANTS**

TYPE PLANT	CONDITIONS	STACK	OVERALL EFFICIENCY	ELECTRICITY MILLS/kWh
PFB	1750F Beds	300F	40.0%	34.1
PFB	1650F Beds	300F	39.2%	34.1
CF	No Scrubber	250F	36.2%	30.5*
AFB	1550F Beds	250F	35.8%	31.7
CF	No Scrubber	300F	35.7%	31.6*
CWS	Wet Scrubber***	175F	33.8%	37.0
CWS	Wet Scrubber***	250F	31.8%	39.8

*3.9% S in Coal Not Permitted. These costs do not include a premium for low-sulfur coal.

**English units are employed in tables and figures in this report, in accordance with engineering design practice. A table of English to metric conversion factors is given on page vi.

***Lime slurry w/onsite calcination.

The overall efficiency is defined as the net station output divided by the higher heating value of the coal fired.

The high efficiency configurations for the PFB plant with beds at 1750 F yields the highest overall efficiency of all the plants evaluated; however, the combustor and gas clean up and solids handling systems for this power plant, that includes a gas turbine, would need considerable further development before it could, in fact, become a reality. The AFB plant also needs further development although its development is advanced compared to the PFB plant. Based on available technology, the conventional furnace with wet scrubber and 175 F stack gas is the best current solution for combustion of high sulfur fuels. There is, however, an economic incentive to develop AFB and PFB as well.

The two "no scrubber" cases would require a coal of less than 0.65 percent sulfur for a 10,788 Btu/lb higher heating value if they are to meet the emission standard of 1.2 lbSO_2/M Btu emission standards common to all of the plants. Premium costs for this higher quality coal were not included in the comparison in Table 107.

Note in Table 107 that the increase in bed temperatures and the addition of the high temperature feedwater heater for the PFB with beds at 1750 F resulted in only a slight increase in the overall efficiency and no difference in the cost of electricity when compared with the PFB plant with 1650 F beds.

The change in the stack temperatures from 250°F to 175 F, in the case of the CWS, yielded improvements in both the overall efficiency and the cost of electricity.

Some insight into the relative costs in dollars for kilowatt ($/kW) for heat release and sulfur and particulate capture for the three plants may be gained by considering the combination of the costs in $/kW for the furnace modules, hot gas filtering, solids handling and stack gas scrubber are appropriate for each plant. This is depicted in Table 106 which is included here for convenience. These combinations of components total $67/kW for the AFB, $123/kW for the PFB and $147/kW for the CWS. Data also included in this table reveal that the total capital costs and the costs of electricity follow a similar progression for the respective plants. As shown in Table 106, a major contributor to the PFB capital cost is the hot gas filtering system. Estimates of hot gas cleanup costs vary from estimator to estimator, depending on design assumptions (such as gas velocity thru granular bed filters). Design assumptions different from GE's could result in lowering the PFB plant cost.

Summaries of the environmental intrusions anticipated from operation of the CWS, AFB, and PFB plants are presented, respectively, in Tables 22, 56, and 78. These tables have been duplicated from other portions of the report.

SO_x emissions are comfortably under the current limit of 1.2 lbSO_2/MBtu (0.52 kg/GJ) of heat release for all three plants, as a result of the selected design conditions, with the PFB showing the greatest margin. In designing for these different degrees of SO_2 removal (85% for AFB, 88% for CWS and 90% for PFB), GE was attempting to ensure compliance with its emission standard (83%) for each system. The greater degrees of control designed into each system were to reflect GE's estimation of the uncertainty in system performance.

Table 106

CAPITAL COST DISTRIBUTIONS AS $/kW
FOR 3600 PSI, 1000 F, 1000 F STEAM POWER PLANTS

	AFB 1550 F	PFB 1650 F	CF 175 F
Major Components			
Steam Turbine-Generator	33.2	27.7	33.6
Furnace Modules	55.8	16.3	57.7
Gas Turbines		28.3	
Hot Gas Filtering		71.4*	
Economizer		2.5	
Solids Handling	11.4	35.6**	
Subtotal	100.3	182.0	91.3
Balance of Plant			
Stack Gas Scrubbers	--	--	89.2
Site Labor	117.8	108.4	126.8
All Other	122.1	98.7	107.5
Subtotal	239.9	207.1	323.5
Contingency	68.0	77.8	84.2
Escalation and Interest	223.8	255.8	273.0
Total Capital Cost ($/kW)	632.	723.	771.
COE (mills/kWh)	31.7	34.1	37.0

*Approximately two-thirds of this cost represents the high temperature/pressure granular bed filter for particle removal from the flue gas. For comparison, an esimate for hot gas filtering for PFB use made by Westinghouse for the ECAS program (ref. 6) using different design assumptions amounted to about $15/kW.

**The Westinghouse estimate for PFB solids handling was about $8/kW (ref. 6).

The AFB and PFB with combustion in the beds at 1550 F and 1650 F, respectively, indicate low levels of NO_x in comparison with the current limit of 0.7 lb NO_x/MBtu of heat release. The CWS requires a well balanced, staged combustion system in order to meet the current NO_x limitations.

In regard to emissions of particulates, each of the plants has little or no margin in comparison with the current limit of 0.1 lb/MBtu of heat release.

The stack gas heaters in the case of the CWS, Table 22, place a greater fraction of the heat rejection at the stack as compared with the corresponding values for the AFB and PFB in Table 56 and 78, respectively.

Water usage is greatest for the CWS and smallest for the PFB plant. The coal requirement would follow the same progression as does water conservation.

The solid waste produced is least for the CWS (on a dry basis) and greatest for the PFB. The PFB plant uses dolomite which has only half the concentration of available lime found in limestone. Since solid wastes from AFB and PFB are dry, some ease in handling may result in comparison with CWS sludge.

The above comparisons have been made using the CWS with 250 F stack gas temperature (Table 22). The environmental intrusions for the CWS with 175 F stack gases would be comparable to the values in Table 22, but these would be a 6 percent reduction where the basis was kilowatt-hours. The requirements for stack gas reheat would be reduced by a factor of 2.5 for the CWS with 175 F stack gas temperature.

The implications of the impact of the sludge and solid wastes produced from the plants can be put in better perspective by considering the quantities of waste resulting from the burning of a ton of coal in each type of plant. Calculations show that the burning of 2000 lb of coal would yield 1540 lb of wet sludge for the CWS, 740 lb of dry product for the AFB plant, and 1060 lb of dry product for the PFB plant.

Extrapolating the above quantity of sludge for the case of CWS of 1000 MW(e) capacity operating over a period of 30 years, a requirement of 800 acres of land would be required for dispoal of sludge. In view of such disposal requirements, there is a strong need to develop regenerable systems to reduce the volume of waste from all of the plants.

2. Studies by TVA

In order to account for uncertainties in the state of technology of some components of the AFB and PFB power plants and to better reflect actual utility practice regarding the costing of certain subsystems of conventional power plants, TVA has prepared some modified estimates for comparison with the capital costs and costs of electricity obtained by GE. These results are shown in Table 108. Shown in this table are the total capital costs in 1975 dollars and corresponding costs accounting for escalation through the construction period.

Table 22

ENVIRONMENTAL INSTRUSION
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-250 F STACK

EMISSIONS	LB/MBtu INPUT	LB/kWh OUTPUT
SO_x	0.867*	0.0093
NO_x	0.65**	0.0070
HC	-	-
Partulates	0.092***	0.00099
THERMAL POLLUTION		
Heat, Rejected Cooling Towers, Btu/kWh		4188
Heat, Rejected Stack, Btu/kWh****		3130
Heat, Rejected Total, Btu/kWh		7318

WASTES	LB/kWh	M LB/DAY
Water Discharge	1.59	28.4
Dry Fly Ash	0.07	1.30
Sludge (Dry Basis)	0.19	3.46

*Based on lime scrubber w/8.5 ft/sec gas velocity thru scrubber. Ca/S ratio = 1.10.
**Based on balanced staged combustion system in conventional boiler.
***Based on electrostatic precipitator upstream of the scrubber.
****Includes all system heat losses except heat rejected in the cooling towers.

Table 56

ENVIRONMENTAL INTRUSION
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

EMISSIONS	LB/MBtu INPUT	LB/kWh OUTPUT
SO_x	1.028*	0.0098
NO_x	0.270**	0.00258
HC	-	-
CO	0.040	0.00038
Particulates	0.099***	0.00094
THERMAL POLLUTION		
Heat, Rejected Cooling Towers, Btu/kWh		4729
Heat, Rejected Stack, Btu/kWh		909
Heat, Rejected Total, Btu/kWh		5636

WASTES	LB/kWh	M LB/DAY
Spent Solids Congolomerate	0.292	5.70
42% Calcium Sulfate 31% Ash 24% Unreacted Lime 3% Carbon		
Water Discharge	1.32	25.8

*This is based on the Ca/S ratio of 2 selected for this study. Data available to EPA suggests that a Ca/S ratio of 2.5 to 3.5 may be required to routinely achieve SO_2 emissions compliance.

**Based upon available data, EPA believes that the NO_x emission level will more typically be in the range of 0.3 to 0.6 lb/MBtu.

***Assumes use of Electrostatic Precipitator as the final stage of flue gas particle removal.

Table 78

ENVIRONMENTAL INTRUSION
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED

EMISSIONS	LB/MBtu INPUT	LB/kWh OUTPUT
SO_2	0.688*	0.0060
NO_x	0.152**	0.0013
HC	-	-
CO	0.020	0.0002
Particulates	0.100***	0.0009

THERMAL POLLUTION	
Heat, Rejected Cooling Towers, Btu/kWh	3967
Heat, Rejected Stack, Btu/kWh	951
Heat, Rejected Total, Btu/kWh	5300

WASTES	LB/kWh	M LB/DAY
Spent Solids Conglomerate	0.3424	7.43
42% Ash Compounds 26% Calcium Sulfate 16% Magnesium Oxide 13% Unreacted Lime 4% Unburned Carbon		
Water Discharge	1.19	25.9

*Based upon dolomite injection into the PFB at a Ca/S ratio of 2.

**Based upon available data, EPA believes that the NO_x emission level will typically be in the range of 0.1-0.4 lb/MBtu.

***Assumes use of high temperature/pressure granular bed filter as final stage of flue gas particulate removal.

Table 108

COST COMPARISON OF GE STUDY VS. TVA REVIEW

Total Capital Costs (1975 dollars)

PLANT TYPE	PLANT OUTPUT MW	GE STUDY		TVA REVIEW**	
		TOTAL COST ($000,000)	COST/KW ($)	TOTAL COST ($000,000)	COST/KW ($)
*CWS @ 175 F	795.5	395.96	497.75	398.03	500.35
AFB	814.3	332.45	408.26	363.14	445.95
PFB	903.8	421.00	465.81	479.45	530.48
Total Capital Cost Escalated (5.5 year construction to mid-1981)					
CWS @ 175 F	795.5	613.74	771.5	616.95	775.6
AFB	814.3	514.70	632.0	562.87	691.2
PFB	903.8	653.10	722.8	743.15	822.3

*Scrubber is lime slurry w/8.5 ft/s gas velocity through scrubber, onsite calcination.

**Estimates by TVA include an uncertainty allowance for components not-yet demonstrated, and revision for some components based upon TVA's experience.

For the CWS, the differences between the costs obtained by GE and the corresponding costs prepared by TVA are small. The major differences result from differing costs assigned to the electrical subsystem by the two organizations.

The cost estimates prepared by TVA for the AFB and PFB plants show significant variance from the corresponding values prepared by GE. In these cases, TVA has assigned an "uncertainty factor" to selected components of the plant that are assumed to have reached a mature level of technology, but have not been applied commercially at full scale. The uncertainty factor was applied as an added percentage of the cost of an item of equipment or system and was assigned a value on the basis of how close to commercialization the item was judged to be.

The allowances accounted for through application of the uncertainty factor are to take care of design changes, addition of equipment, and technological advances. The modifications do not incorporate development and startup costs associated with obtaining a state-of-the-art process.

The specific items to which an uncertainty factor was applied in the fluidized bed plants were the steam generators, fuel injection systems, spent solids and dust coolers, and portions of the hot gas cleanup systems.

As a further extension of the study, TVA developed cost estimates for the alternative scrubbing systems for the CWS and alternate schemes for disposal of the sludge from the CWS and solid wastes from the AFB and PFB plants. In conjunction with these studies, TVA took into account the cost associated with sludge and waste disposed over a period of 30 years.

The scrubbing systems considered were as follows:

a. Lime scrubbing with onsite calcination

b. Lime scrubbing without onsite calcination

c. Limestone scrubbing

d. Magnesium oxide regenerable scrubbing (production of sulfuric acid)

The variety of disposal schemes involved combinations of treatment and nontreatment of the wastes from scrubbers and fluidized combustion plants in combination with choices of clay-lined ponds or clay-lined, diked impoundments that were located either onsite or offsite.

The total capital costs, expressed in dollars per kilowatt and the cost of electricity expressed in mills per kilowatthour are summarized in Table 127. Among the scrubber alternatives the cost of electricity is the lowest for the magnesium oxide regenerable scrubbing system. This prediction, coupled with the alleviations of waste disposal problems provides incentive for commercialization of regenerable systems. The alternate scrubber systems with 30-year sludge disposal showed little variation in cost of electricity.

Table 127

COMPARISONS OF COSTS CONSIDERING VARIOUS TYPES OF SCRUBBERS AND ALTERNATE METHODS OF WASTE DISPOSAL

	TOTAL CAPITAL $/kW	COST OF ELECTRICITY (Mills/kWh)			
		CAPITAL	O&M	FUEL	TOTAL
Conventional With Scrubber					
GE/CWS/250F/5 yr. disp./lime w/calcination/747 MW	835.4	26.40	2.61	10.73	39.83
GE/CWS/175F/5 yr. disp./lime w/calcination/795 MW	771.3	24.38	2.45	10.10	36.93
TVA/CWS/175/30 yr. disp./lime w/calcination/795 MW	782.3	24.73	3.74	10.10	38.57
TVA/CWS/175F/30 yr. disp./lime (purchased)/795 MW	758.9	23.99	3.92	10.10	38.00
TVA/CWS/175F/30 yr. disp./limestone/795 MW	773.9	24.47	3.41	10.10	37.99
TVA/CWS/175F/MgO/Regenerable/795 MW W/H_2SO_4 credit	728.0	23.01	2.37	10.10	35.48
TVA/CWS/175F/MgO/Regenerable/795 MW NO H_2SO_4 credit	728.0	23.01	3.55	10.1	36.66
Fluidized Bed Power Plants					
GE/AFB/onsite disposal (30 yr.) 814 MW	654.0	20.67	2.61	9.53	32.81
GE/AFB/offsite disposal (30 yr.) 814 MW	648.5	20.50	2.77	9.53	32.80
GE/PFB/onsite disposal (30 yr.) 904 MW	745.0	23.55	2.98	8.71	35.24
GE/PFB/offsite disposal (30 yr.) 904 MW	739.6	23.38	3.16	8.71	35.25
TVA/AFB/uncertainties added/onsite disposal (30 yr.) 814 MW	712.4	22.52	2.61	9.53	34.66
TVA/AFB/uncertainties added/offsite disposal (30 yr.) 814 MW	706.4	22.33	2.77	9.53	34.63
TVA/PFB/uncertainties added/onsite disposal (30 yr.) 904 MW	845.1	26.72	2.98	8.71	38.41
TVA/PFB/uncertainties added/offsite disposal (30 yr.) 904 MW	839.7	26.55	3.16	8.71	38.42
GE/AFB/no disposal/814 MW	632	20.00	9.50	2.20	31.7
GE/PFB/no disposal/904 MW	723	22.90	8.70	2.50	34.1

The results in Table 127 also indicate that the economics of the AFB plant are favorable in comparison with the PFB plant. The uncertainties are greater for PFB plants, plus additional capital outlays are required. These factors contribute significantly to higher capital costs and cost of electricity in comparison with AFB plants. Comparison of the estimated costs of electricity indicate that AFB offers the potential for a savings in comparison with all of the CWS options. PFB also offers potential savings if uncertainties are not included; if uncertainties are included, the estimated cost of electricity is about the same for PFB and CWS. However, the estimated COE for the CWS alternatives and the AFB and PFB alternatives (with uncertainty) are so close (within 12%) that all are considered within the competitive range for further consideration.

CONCLUSIONS AND RECOMMENDATIONS

A. Conclusions

Several observations become evident upon examination and comparison of the performance and economic results that have been generated from the study of CWS, AFB, and PFB plants. It is important to keep in mind that developmental and startup costs associated with obtaining a state-of-the-art process have not been incorporated in the results. The salient conclusions are itemized as follows:

1. The AFB power plant offers a near-term promising alternative to the CWS. The comparison on the basis of the costs of electricity indicate an approximate savings of 9 to 14 percent (depending on whether or not an uncertainty allowance is applied) in favor of the AFB as opposed to the CWS using lime or limestone for capture of sulfur.

2. The economics of the PFB plant may be severely affected by stringent hot gas cleanup requirements and high pressure (10 atmospheres) solids handling requirements. The comparisons on the basis of cost of electricity between the CWS using lime or limestone and a PFB plant using dolomite for capture of sulfur indicate no savings in using the PFB if allowances for uncertainties are considered in evaluating the PFB plant. On the other hand, if no uncertainty allowance is applied, the PFB plant offers a 7 percent savings in cost of electricity in comparison with the CWS.

   The superiority of the overall efficiency of 39.2 percent for the PFB plant in comparison with, typically, 35.8 percent and 33.8 percent for the AFB plant and the CWS, respectively, is offset by large capital requirements for gas cleanup equipment for the PFB plant. Estimates for hot gas cleanup costs vary from estimator to estimator, depending on the design assumptions used; use of different assumptions from those used by GE could increase the apparent savings for PFB.

3. The performance of the CWS is penalized by additional power requirements for operation of the scrubber and (much greater) by stack gas reheat requirements. For example, the difference in the cost of electricity for a CWS in which the gases existing from the scrubber are reheated to 250 F instead of to 175 F amounts to a penalty of approximately 8 percent. Thus, there are significant differences in the economics of the CWS for different reheat temperatures of the stack gases.

4. Application of alternative scrubber systems now developed do not affect the economics of the CWS enough to change its position relative to AFB and PFB plants.

   Estimates for the CWS utilizing a magnesia slurry scrubber suggest that a reduction in the cost of electricity may be attained relative to the scrubber using lime and limestone. However, the magnesia scrubber remains to be fully developed and regeneration of the sorbent is unproven.

B. Recommendations

The following recommendations are made for extending the studies reported herein:

1. It is recommended that the study be extended to include intermediate load duty since most utility power systems will in all likelihood require this type of service from all three types of plants.
2. In view of the fact that such extensive areas of land will be required for disposal of sludge/solid wastes over the life of either of the types of plant studied, it is recommended that development of systems for sorbent regeneration be accelerated.

GE CONCEPTUAL DESIGNS AND COST ESTIMATES

A. STUDY GROUND RULES

The methodology and ground rules used in the evaluation of a conventional steam plant with stack gas scrubbers for sulfur removal are identical with those applied to steam power plants in the Energy Conversion Alternatives Study. Those elements that are not dealt with in the detailed text will be briefly reviewed here.

The focus was on baseload plants with 30 years useful life and 90 percent plant availability. The capital costs were evaluated for mid-1975 costs, as if all elements were fully developed. All plants were treated as mature and no development costs were included. During construction, prices would escalate 6.5 percent per year. Interest during construction would be at 10 percent per year; the fixed charge rate per year of operation would be 18 percent of plant final cost. The time for construction, 5.5 years, was determined on the basis of the total man-hours of field labor content. The S-curve for expenditures resulted in escalation and interest during construction 0.548 times the total plant cost without those factors.

The fuel was a high-sulfur Illinois coal (No. 6) with the characteristics defined in Table 1. The emission standards for flue gas are presented in Table 2.

Several efficiencies are reported for each type of plant. The thermodynamic efficiency was the generator output divided by the heat input to the steam cycle. The power plant efficiency and the overall efficiency were both equal to net station output divided by the higher heating value of the coal fired.

The heat rejection from condensers was to mechanical draft evaporative cooling towers. Power plant operation was evaluated for a 59 F air ambient with 60 percent relative humidity. The resulting wet-bulb temperature was 51.5 F.

Uniformity of treatment of all steam plants was assured by use of the same team as contributors. The heat input for combustion and heat exchange to steam were studied by the Foster Wheeler Energy Corporation. The pressurizing gas turbines for the PFB were evaluated by the General Electric Gas Turbine Products Division. Investigations of the steam turbine and its cycle specifications were done by the General Electric Large Steam Turbine Department. The wet lime scrubber system, the heat rejection equipment, and all balance of plant labor and equipment were evaluated by the Bechtel Corporation. Bechtel also provided architect-engineer layouts of the plant site and plant arrangement. The systems integration was done by the General Electric project team.

Operating and maintenance costs were assessed to each plant on the basis of estimates provided by the boiler manufacturer, Foster-Wheeler, the steam turbine manufacturer, GE, and the architect-engineer, Bechtel, for the scrubber system and consumables such as limestone. The operation manning requirement was evaluated by the Installation and Service Engineering Staff of General Electric.

Table 2

EMISSION STANDARDS

Pollutant	Standard (Lbs/MBtu Heat Input)
SO_x	1.2
NO_x	0.7
Particulates	0.1

B. CONVENTIONAL/WET SCRUBBER POWER PLANT

1. INTRODUCTION

A steam power plant with wet gas scrubber to reduce stack gas emissions is a distinct advance over the numerous conventional coal-burning steam power plants that cannot meet today's emission standards except by burning low-sulfur coal or converting to oil firing. There will be a direct competition between plants with conventional furnaces with stack gas cleanup, and alternatives such as fluidized bed furnaces that capture sulfur products during the combustion process.

The simplified cycle schematic presented as Figure 1 shows the major pieces of equipment. The coal and air are fired with staged combustion of the pulverized coal to limit generation of thermal NO_x products. The furnace and its elements (steam turbine, condenser, and cooling towers) are all proven conventional elements. Gas leaves the unit at 300 F after passing through electrostatic precipitators that reduce the burden of fly ash in the flue gas. The gas enters the scrubber and is quenched to 125 F with lime slurry sprays. Sulfur is removed as calcium sulfite and calcium sulfate, which precipitates out in the sludge pond. Lime is continually replenished, using an onsite calciner for limestone.

The water-vapor-saturated flue gas at 125 F is next reheated to either 175 F or 250 F. The means is a blending with a large quantity of air that has been preheated above that temperature by steam extracted from the steam turbine cycle.

The system parameters are presented in Table 3. The Illinois No. 6 coal contains 3.9 percent sulfur. Eighty-three percent of the sulfur must be captured to meet the environmental emission limit of 1.2 pounds of sulfur dioxide per million Btu of fuel heat release. The wet scrubbers are specified to capture 90 percent of the flue gas sulfur burden when 4.5 percent sulfur was present in the coal. With the specified margin of performance capability, the plant operation is assured of meeting current standards for flue gas emissions. The consumption of lime is minimized by the intimate mixing in the wet scrubbers. In addition the recirculating system provides for reuse of lime in solution in the clarified water recirculated from the sludge pond.

The steam cycle uses conventional conditions for a supercritical reheat unit with seven feedwater heaters. The large extraction of steam at the turbine crossover pressure for stack gas reheat approaches the limit set for conventional practice. The condenser back pressure was chosen to optimize the total

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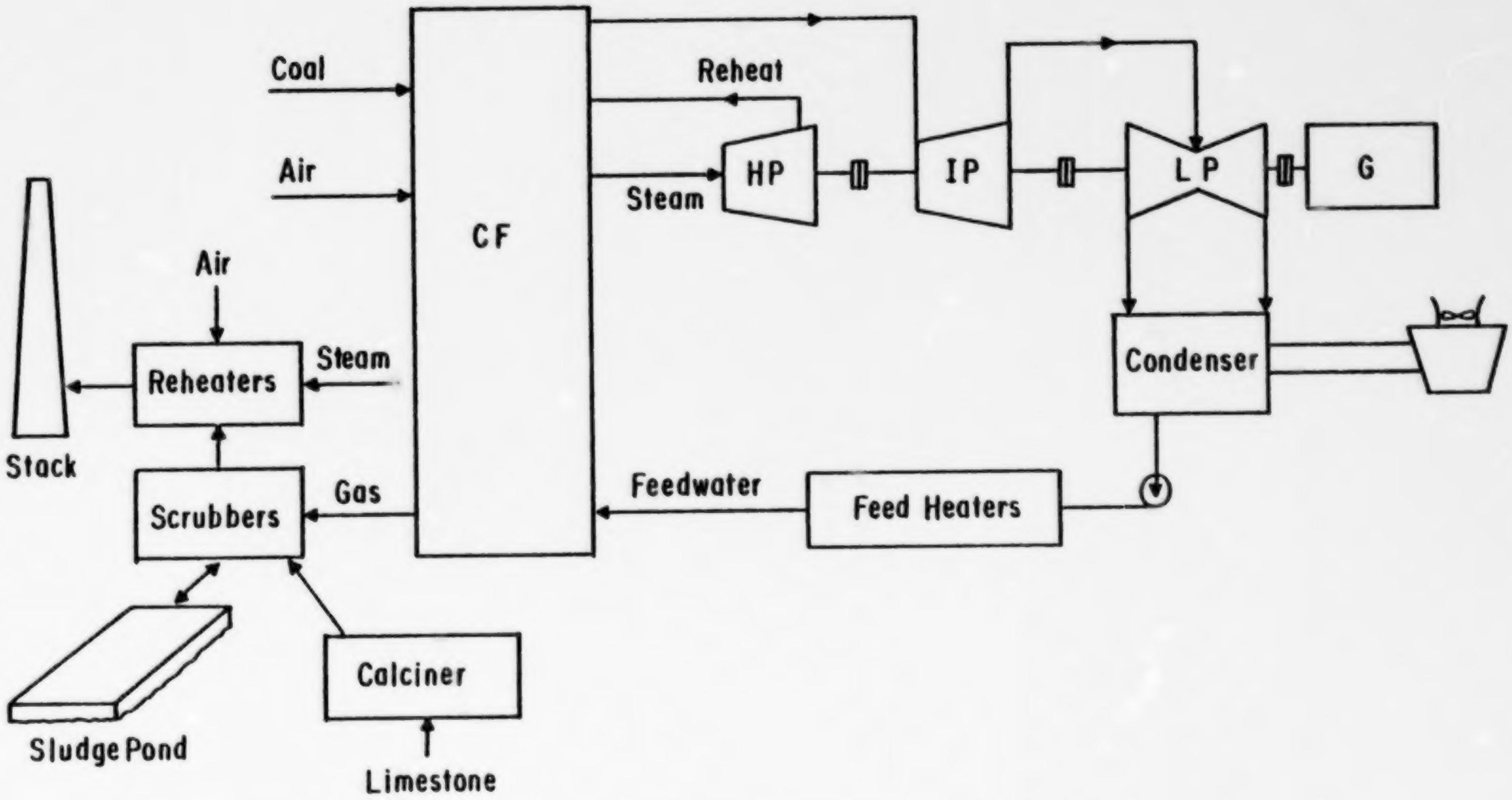

Coal
Air
CF
Reheat
Steam
HP
IP
L P
G
Condenser
Feed Heaters
Feedwater
Air
Steam
Reheaters
Stack
Gas
Scrubbers
Sludge Pond
Calciner
Limestone

Figure 1. Conventional Steam Plant—with Wet Gas Scrubbing

Table 3

SYSTEM PARAMETERS
CONVENTIONAL STEAM--WET GAS SCRUBBERS

PARAMETER	VALUE OR DESCRIPTION
Fuel	
Illinois No. 6	10788 Btu/LB Higher Heating Value 1\$/MBtu
Limestone	For Sulfur Capture 0.16 LB/LB Coal
Furnace	
Radiant Section	Pulverized Coal Fired
Convection Section	Superheat and Reheat
Prime Cycle--Steam Plant	
Working Fluid	Steam
Turbine Inlet	3500 PSI, 1000 F
Reheat	659 PSI, 1000 F
Condenser	2.3" Hga, 106 F
Final Feedwater	4378 PSI, 505 F
Heat Rejection	
Wet Mechanical Draft Cooling Towers	20 Cells
Stack Gas Temperature	250 F

cost of electricity with respect to turbine output and cost, heat rejection system cost, and auxiliary power consumption.

The first case set stack gas temperature at 250 F in conformance with former conventional steam power plant practice. The influence of stack gas temperature is far greater than normal for this steam plant configuration. In an additional case the corrosive component dew points in the flue gas are assumed to be at or below 125 F by the scrubbing process. As a result a lower stack temperature was deemed to be permissible. A subsequent evaluation was made for 175 F stack temperature. Details of this case will only be presented after a complete appraisal of the 250 F stack case.

The net power from the 250 F stack plant would be 747 MW, representing a 32 percent conversion efficiency from coal to dispatched power. The net power from the 175 F stack plant would be 795 MW, with a 34 percent conversion efficiency.

2. CYCLE DESCRIPTION

A more detailed plant schematic is presented in Figure 2. State points and stream flows are shown wherein the enthalpy values are referenced to 32 F water for steam and water and to an 80 F zero reference for air, combustion gases, and solids. The advanced feature of this power system is the use of wet flue gas scrubbers with a conventional boiler to generate steam from high-sulfur coal for a conventional steam turbine cycle with a single reheat of the steam.

Steam Turbine-Generator Cycle

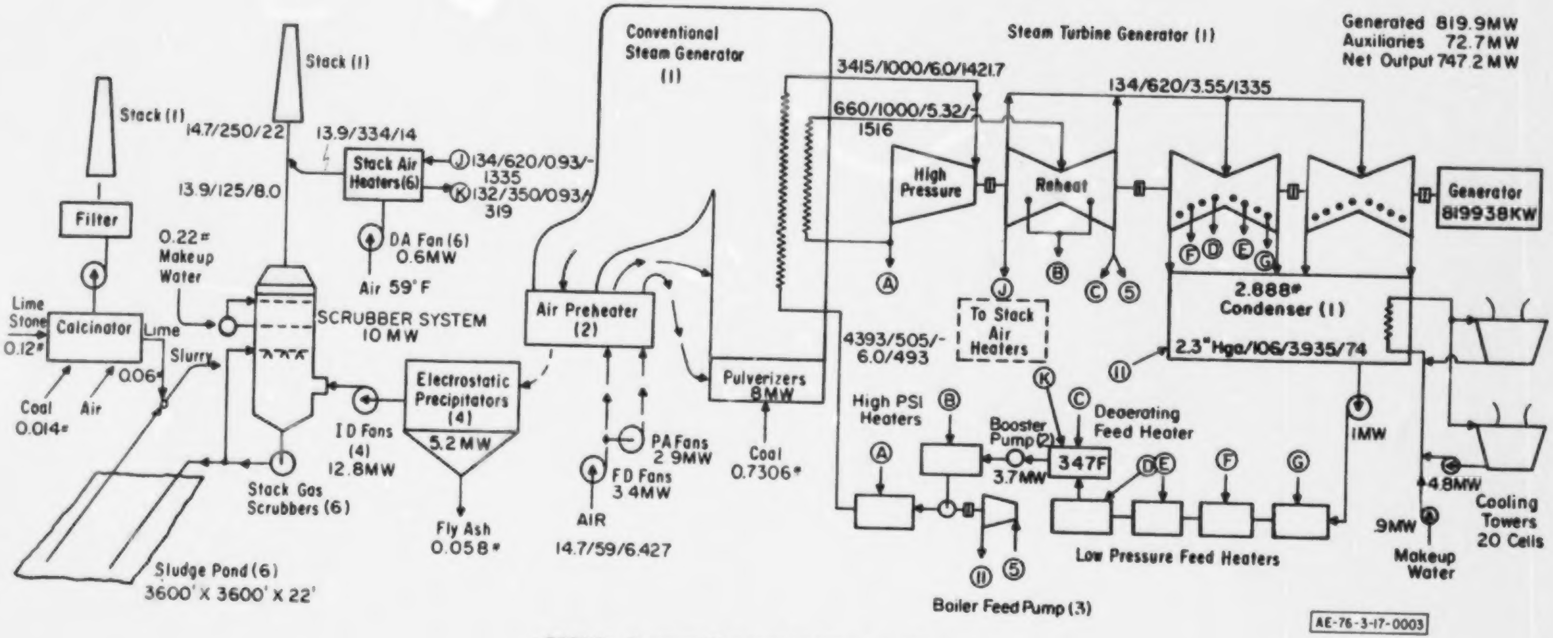
The steam turbine is contained in four shells connected in tandem with a single 820 MW generator. The low pressure stages have four parallel flows exhausting downward into a common condenser. The condenser coolant is water recirculated in a closed circuit to evaporative cooling towers. The regenerative feedwater heating cycle has four low-pressure feedwater heaters, a deaerating feedwater heater, and two high-pressure feedwater heaters. Part of the steam exhausted from the high-pressure turbine is used in feedwater heating, while the rest is returned to the boiler to be reheated to 1000 F. Part of the steam from the reheat turbine exhaust is used for driving the boiler feed pump. The exhausts from those drive turbines are routed to the main condenser. All other pump drives are electric motor driven and appear in the detailed account of auxiliary losses. The boiler feed pump and its drive are an integral part of the steam cycle and are fully accounted for in the heat balance for the steam turbine-generator.

The final feedwater would be 505 F for the 100 percent operation. All major components were specified for continuous performance capability at a flow margin of 5 percent above the intended plant operating flow. The steam cycle at the valves wide open (VWO) point would pass the intended flow with margin, and the designated 510 F feed temperature would then exist. It is important in conventional steam systems that the operations be evaluated at the 100 percent operating point, where performance is guaranteed, and not at the specification condition for design with margin.

Conventional Steam Generator

The coal to be fired is dried by the primary air-flow at the eight ball mill pulverizers. Between 15 and 20 percent of the total air is heated to 633 F in the hottest sector of the air preheater as primary air. This air serves to dry the coal, to convey the pulverized coal to the burners, and to consummate the initial combustion process. The remainder of the air is preheated to 585 F and delivered to the burners as secondary air.

The water circuitry in the steam generator provides water walls, radiant energy absorption surfaces, convection and radiant surfaces for superheating and reheating of steam, and an economizer to bring the flue gas to 740 F as it leaves the boiler and enters the air preheater. Slag is removed from the boiler furnace beneath the firing zone, fly ash from a hopper just before the air preheater. These solids, representing 15 and 10 percent of the total ash,


Stack (1)
Filter
Lime Stone 0.12#
Calcinator
Coal 0.014#
Air
0.06#
Lime
Slurry
0.22# Makeup Water
Stack (1)
14.7/250/22
13.9/125/8.0
13.9/334/14
Stack Air Heaters (6)
Ⓙ 134/620/093/- 1335
Ⓚ 132/350/093/- 319
DA Fan (6) 0.6MW
Air 59° F
SCRUBBER SYSTEM 10 MW
Stack Gas Scrubbers (6)
Sludge Pond (6) 3600' X 3600' X 22'
I D Fans (4) 12.8MW
Electrostatic Precipitators (4)
5.2 MW
Fly Ash 0.058#
Conventional Steam Generator (1)
Air Preheater (2)
PA Fans 2.9MW
F D Fans 3.4MW
AIR 14.7/59/6.427
Pulverizers 8MW
Coal 0.7306#
3415/1000/6.0/1421.7
660/1000/5.32/- 1516
4393/505/- 6.0/493
High Pressure
Reheat
Steam Turbine Generator (1)
134/620/3.55/1335
Generator 819938KW
Generated 819.9MW
Auxiliaries 72.7MW
Net Output 747.2 MW
Ⓐ Ⓑ Ⓒ ⑤ Ⓙ
Ⓕ Ⓓ Ⓔ Ⓖ
To Stack Air Heaters
2.888#
Condenser (1)
2.3"Hga/106/3.935/74
⑪
1MW
High PSI Heaters
Booster Pump (2)
3.7MW
Ⓚ Ⓒ
Deaerating Feed Heater
347F
Ⓓ Ⓔ Ⓕ Ⓖ
Low Pressure Feed Heaters
Boiler Feed Pump (3)
⑪ ⑤
4.8MW
.9MW
Makeup Water
Cooling Towers 20 Cells
AE-76-3-17-0003

LEGEND: Pressure/Temperature/Flow Rate/Enthalpy
PSIA/°F/Million Pounds Per Hour/BTU Per Pound
#Million Pounds Per Hour

Figure 2. Conventional Steam Cycle with Wet Gas Scrubbers

respectively, are sluiced to the sludge pond. The electrostatic precipitators, with an efficiency of 98.6 percent, collect another 75 percent of the total ash, leaving only 0.75 percent in the gas flow to the wet scrubbers. The collected fly ash is stored in dry silos for shipment offsite. Induced draft fans follow the electrostatic precipitators.

Wet Gas Scrubbers

The wet gas scrubbers apply a spray of recirculated hot water that is rich in lime in order to capture sulfur compounds. The remaining fly ash will be washed out of the flue gas also. Following the main reactive spray there is a demisting spray that recirculates a makeup water and captured drift mixture. Carry over of the slurry and lime are avoided by this means.

Lime And Sludge Systems

A continual removal of sludge and a continual replenishment of lime and water is required. The sludge is flushed to the sludge settling ponds in a stream comprising 10 percent undissolved solids. The return water from the pond is enriched with lime produced in the coal-fired calcinator from limestone feedstock.

The makeup water moves in a counterflow mode. It is first applied in the mist eliminator recycle wash bleedoff replenishing the SO_2 absorber recycle liquids, and ultimately becomes part of the sludge and water mixture that accumulates in the settled portion of the sludge pond.

Stack And Reheat System

The flue gas at 125 F leaves the wet scrubber saturated with water vapor and with many constituents at or near their dew point temperatures. It has been determined that normal gas heaters cannot have suitable service lives when heating such a corrosive gas mixture. The alternative to direct heating is to blend into the flue gas a large flow of air that has been separately heated. Figure 2 shows that 14 Mlb/h of air heated to 334 F blend with 8 Mlb/h of flue gas to produce a 250 F stack temperature. The stack air heaters use steam withdrawn from the steam cycle as their heating medium. The stack and flues are lined, to withstand attack from the flue gases.

Overview

The major components of this system are conventional and of proven reliability in utility service. The wet scrubber system introduces an added need for maintenance and for the avoidance of corrosive attack by lime and cool flue gas. The subdivision into six parallel scrubbers and the subdivision of critical pumping functions in the scrubber system should assure that at most one-sixth of the capacity would be down at any time.

3. MAJOR CYCLE COMPONENTS

Components for conventional steam plants are specified for continuous operation with flows 5 percent greater than required for normal operation. Insofar as Figure 2 depicts 100 percent plant operation on a 59 F day, the individual specifications for the boiler, turbine, and scrubber will require greater capacities at their design points. The exact matching has been accomplished on the basis of an exact steam-turbine heat balance, which dictates the heat to steam for the boiler, and the boiler efficiency, which in turn dictates the fuel requirement.

This section will consider the specified performance for the steam turbine-generator, the boiler, the scrubber system, and the heat rejection system. The latter two are furnished as balance-of-plant equipment. All other balance-of-plant items will be specified in a subsequent section.

Conventional Furnace-Steam Generator

The general layout of the conventional supercritical once-through steam generator is shown in Figure 3. Eight ball mill coal pulverizers are located at the base elevation. The burners are arrayed about the radiant furnace section. The combustion gas flows upward over superheater sections, then downward in parallel paths through the reheater and the primary superheater, and finally emerges from the economizer. Figure 4 presents a preliminary heat-and-mass balance at the specified design flows. The final configuration differed in that the induced draft fans (IDF) were located after the electrostatic precipitators instead of ahead of these units. The heat to steam for this boiler was 87.1346 percent of the fuel higher heating value.

Steam Turbine-Generator

The heat balance for the steam cycle (250 F case) is presented in Figure 5 for operation at the 100 percent rated power condition of 820 MW. The rating at the valves wide open (VWO) point would be 860 MW. The seven feedwater heaters and the throttle and reheat conditions are typical for supercritical reheat units today. The unusual feature is the extraction of 926,000 lb/hr of steam for stack gas heating service. The effect on the steam turbine cycle is as if a separate condenser were located at the 134 psi level. The reduction of steam flow to the low pressure stages reduces generator output and also the condenser and cooling-tower heat rejection load.

The steam turbine comprises four shells. The high-pressure turbine, the reheat turbine, and two double-flow low-pressure condensing turbines are arranged in tandem with the single generator.

The foundation and arrangement drawing of Figure 6 gives the overall dimensions of the unit. The last-stage turbine buckets are 33.5 inches long. These are the largest buckets applied to 3600 rpm turbines for fossil-fired service. The unit is characterized as "TC4F33.5," indicating tandem compound, four exhaust flows, with 33.5 inch last-stage buckets.

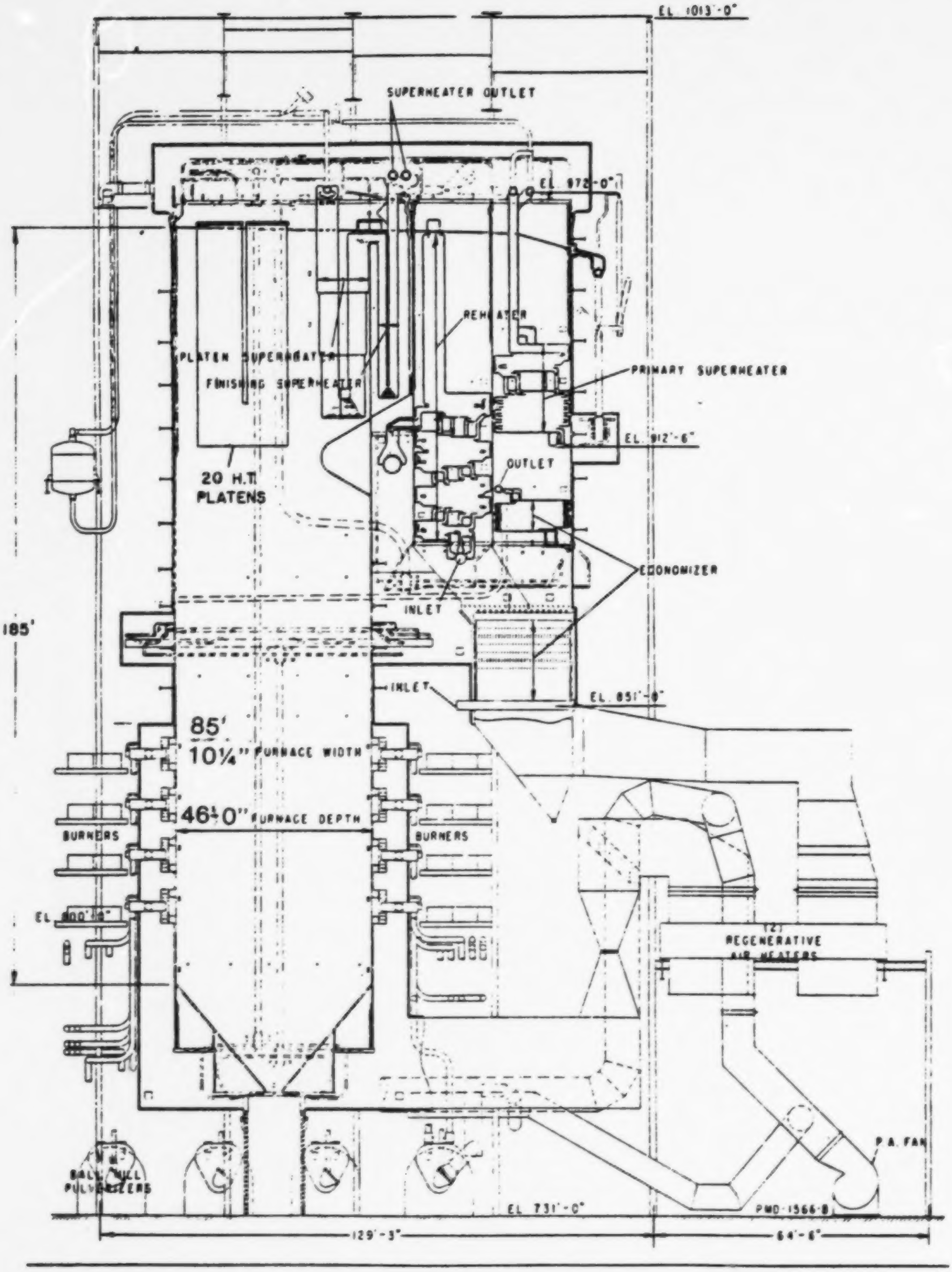

EL 1013'-0"
SUPERHEATER OUTLET
EL 972'-0"
REHEATER
PLATEN SUPERHEATER
FINISHING SUPERHEATER
PRIMARY SUPERHEATER
EL 912'-6"
20 H.T. PLATENS
OUTLET
ECONOMIZER
INLET
185'
INLET
EL 851'-0"
85' 10¼" FURNACE WIDTH
46'-0" FURNACE DEPTH
BURNERS
BURNERS
EL 800'-0"
(2) REGENERATIVE AIR HEATERS
BALL MILL PULVERIZERS
P.A. FAN
EL 731'-0"
PMD-1566-B
129'-3"
64'-6"

Figure 3. Conventional Boiler--Supercritical Once-Through Coal Firing

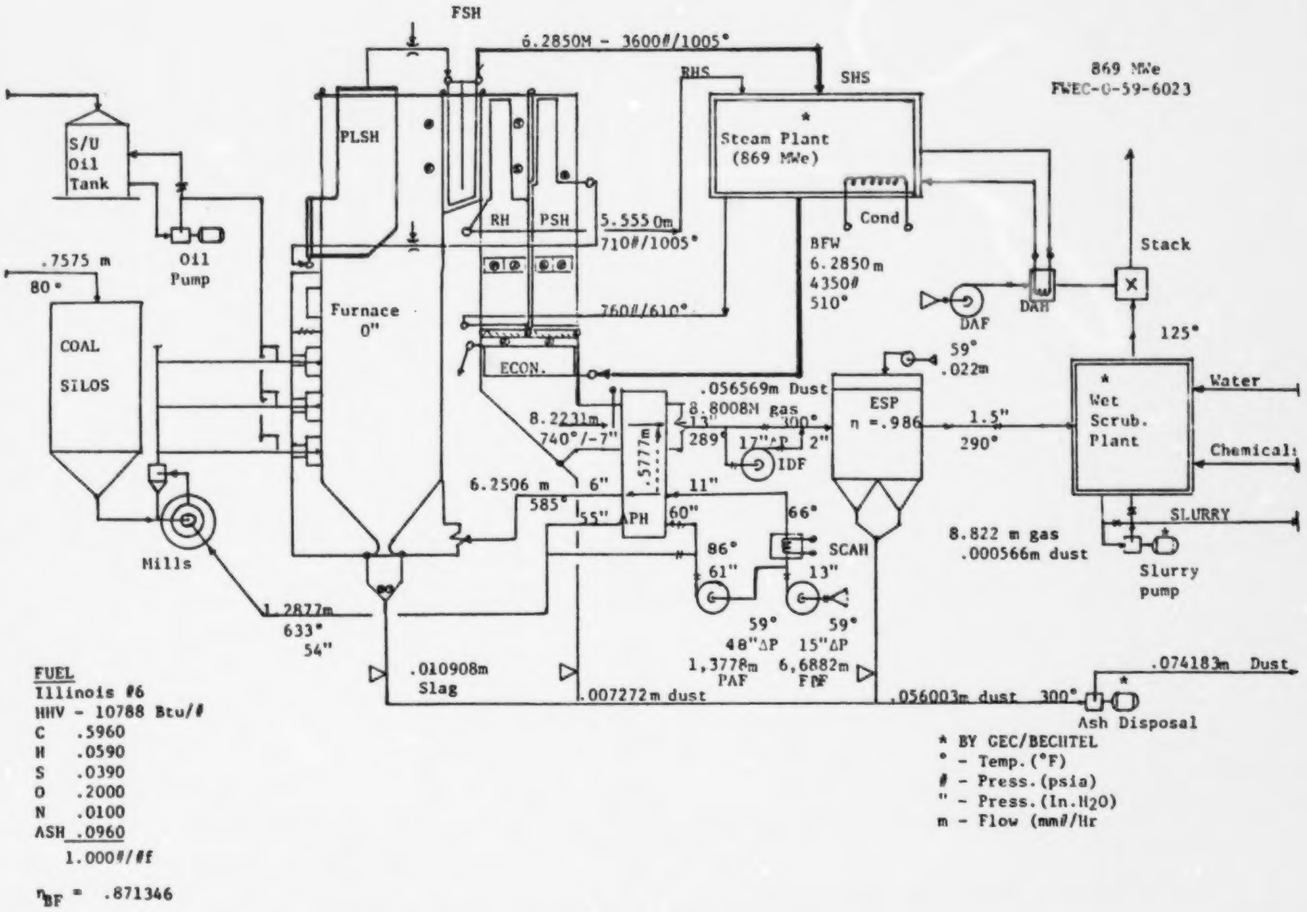

FSH
6.2850M - 3600#/1005°
RHS
SHS
869 MWe
FWEC-0-59-6023
S/U Oil Tank
Oil Pump
PLSH
RH
PSH
5.5550m
710#/1005°
*
Steam Plant (869 MWe)
Cond
BFW
6.2850m
4350#
510°
Stack
.7575 m
80°
COAL SILOS
Furnace 0"
760#/610°
ECON.
DAF
DAH
59°
.022m
125°
.056569m Dust
8.8008M gas
8.2231m
740°/-7"
13"
300°
289°
17"ΔP
2"
IDF
ESP
n =.986
1.5"
290°
*
Wet Scrub. Plant
Water
Chemical:
.5777m
6.2506 m
585°
6"
11"
55"
APH
60"
66°
SCAH
SLURRY
8.822 m gas
.000566m dust
Slurry pump
Mills
86°
61"
13"
1.2877m
633°
54"
59°
48"ΔP
1,3778m
PAF
59°
15"ΔP
6,6882m
FDF
.010908m
Slag
.007272m dust
.056003m dust
300°
*
.074183m
Dust
Ash Disposal
FUEL
Illinois #6
HHV - 10788 Btu/#
C .5960
H .0590
S .0390
O .2000
N .0100
ASH .0960
1.000#/#f
ηBF = .871346
* BY GEC/BECHTEL
° - Temp.(°F)
# - Press.(psia)
" - Press.(In.H2O)
m - Flow (mm#/Hr

Figure 4. Conventional Steam Plant Flow

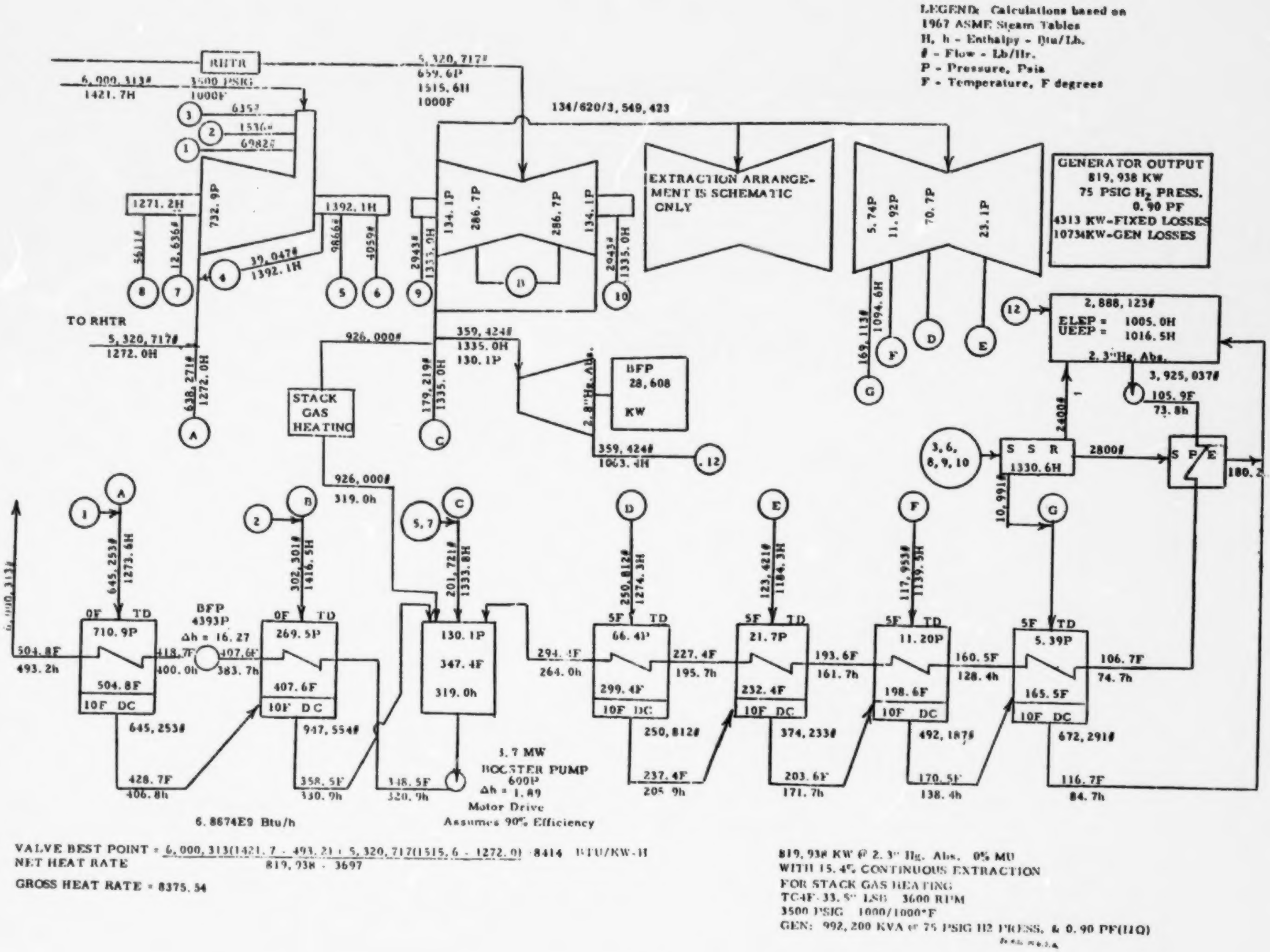
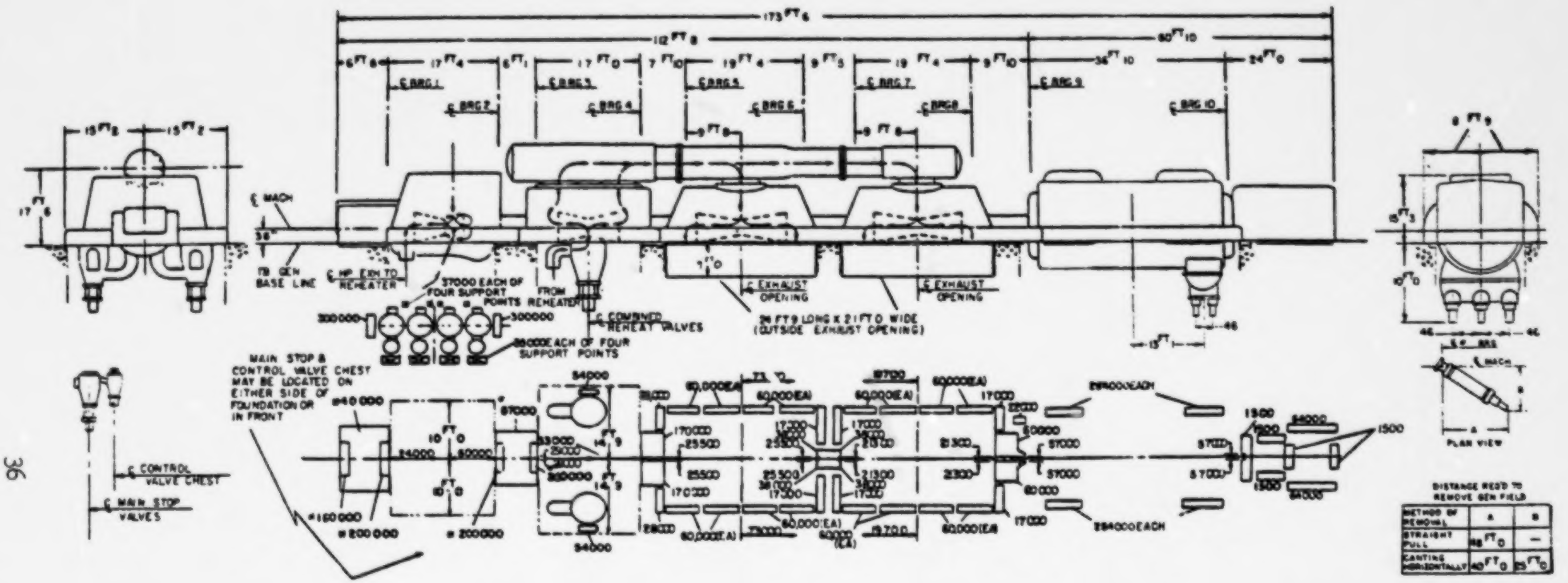

LEGEND: Calculations based on
1967 ASME Steam Tables
H, h - Enthalpy - Btu/Lb.
# - Flow - Lb/Hr.
P - Pressure, Psia
F - Temperature, F degrees
RHTR
6,000,313#
1421.7H
3500 PSIG
1000F
6353
1536#
6982#
732.9P
1271.2H
1392.1H
5611#
12,636#
39,047#
1392.1H
9866#
4059#
TO RHTR
5,320,717#
1272.0H
638,271#
1272.0H
5,320,717#
659.6P
1515.6H
1000F
134/620/3,549,423
134.1P
286.7P
286.7P
134.1P
2943#
1335.0H
2943#
1335.0H
EXTRACTION ARRANGE-
MENT IS SCHEMATIC
ONLY
5.74P
11.92P
70.7P
23.1P
GENERATOR OUTPUT
819,938 KW
75 PSIG H_2 PRESS.
0.90 PF
4313 KW-FIXED LOSSES
10734KW-GEN LOSSES
926,000#
359,424#
1335.0H
130.1P
179,219#
1335.0H
STACK
GAS
HEATING
BFP
28,608
KW
2.8"Hg.Abs.
359,424#
1063.4H
169,113#
1094.6H
2,888,123#
ELEP = 1005.0H
UEEP = 1016.5H
2.3"Hg. Abs.
3,925,037#
105.9F
73.8h
2400#
2800#
S S R
1330.6H
10,991#
S P E
180.2
926,000#
319.0h
645,253#
1273.6H
302,301#
1416.5H
201,721#
1333.8H
250,812#
1274.3H
123,421#
1184.3H
117,953#
1139.5H
6,000,313#
504.8F
493.2h
0F
TD
710.9P
504.8F
10F DC
BFP
4393P
Δh = 16.27
418.7F
400.0h
407.6F
383.7h
269.5P
407.6F
10F DC
130.1P
347.4F
319.0h
294.4F
264.0h
5F
TD
66.4P
299.4F
10F DC
227.4F
195.7h
21.7P
232.4F
193.6F
161.7h
11.20P
198.6F
160.5F
128.4h
5.39P
165.5F
106.7F
74.7h
645,253#
428.7F
406.8h
947,554#
358.5F
330.9h
348.5F
320.9h
3.7 MW
BOOSTER PUMP
600P
Δh = 1.89
Motor Drive
Assumes 90% Efficiency
250,812#
237.4F
205.9h
374,233#
203.6F
171.7h
492,187#
170.5F
138.4h
672,291#
116.7F
84.7h
6.8674E9 Btu/h
VALVE BEST POINT = 6,000,313(1421.7 - 493.2) + 5,320,717(1515.6 - 1272.0) / 819,938 - 3697 = 8414 BTU/KW-H
NET HEAT RATE
GROSS HEAT RATE = 8375.54
819,938 KW @ 2.3" Hg. Abs. 0% MU
WITH 15.4% CONTINUOUS EXTRACTION
FOR STACK GAS HEATING
TC4F-33.5" LSB 3600 RPM
3500 PSIG 1000/1000°F
GEN: 992,200 KVA @ 75 PSIG H2 PRESS. & 0.90 PF(HQ)

Figure 5. Conventional Furnace with Wet Scrub—250 F Stack


173 FT 6
112 FT 8
60 FT 10
6 FT 8
17 FT 4
6 FT 1
17 FT 0
7 FT 10
19 FT 4
9 FT 3
19 FT 4
9 FT 10
36 FT 10
24 FT 0
℄ BRG 1
℄ BRG 2
℄ BRG 3
℄ BRG 4
℄ BRG 5
℄ BRG 6
℄ BRG 7
℄ BRG 8
℄ BRG 9
℄ BRG 10
9 FT 8
9 FT 8
15 FT 8
15 FT 2
17 FT 6
℄ MACH
36"
TB GEN BASE LINE
℄ HP EXH TO REHEATER
37000 EACH OF FOUR SUPPORT POINTS
FROM REHEATER
300000
300000
℄ COMBINED REHEAT VALVES
38000 EACH OF FOUR SUPPORT POINTS
7 FT 0
℄ EXHAUST OPENING
℄ EXHAUST OPENING
36 FT 9 LONG X 21 FT 0 WIDE (OUTSIDE EXHAUST OPENING)
13 FT 1
46
8 FT 9
15 FT 3
10 FT 0
46
46
℄ GEN BRG
℄ MACH
A
B
PLAN VIEW
MAIN STOP & CONTROL VALVE CHEST MAY BE LOCATED ON EITHER SIDE OF FOUNDATION OR IN FRONT
℄ CONTROL VALVE CHEST
℄ MAIN STOP VALVES
#40 000
#160 000
#200 000
#200 000
87000
10 FT 0
10 FT 0
24000
60000
34000
34000
14 FT 9
14 FT 9
170000
25500
17300
60,000(EA)
19700
17000
22000
60000
57000
284000 EACH
1500
1300
34000

DISTANCE REQ'D TO REMOVE GEN FIELD

METHOD OF REMOVAL	A	B
STRAIGHT PULL	48 FT 0	—
CANTING HORIZONTALLY	40 FT 0	25 FT 0

NOTES

1 STEAM CONDITIONS 3500 PSIG-1000/1000 °F REHEAT WITH 33½ IN LAST STAGE BUCKETS

2 HEAVIEST PIECE DURING ERECTION - (GENERATOR STATOR) 760000 LBS
HEAVIEST PIECE AFTER ERECTION - (GENERATOR FIELD ROTOR 180000 LBS

3 160000 & 200000 LB LOADINGS DO NOT OCCUR SIMULTANEOUSLY BUT ARE SUPERIMPOSED ON 40000 LB LOAD 160000 LB LOAD IS ZERO FOR NORMAL OPERATION FOR FULL VALUE OF 160000 LB LOAD 200000 LB LOAD IS ZERO

4 THE COMBINED REHEAT VALVE ARRANGEMENT INCLUDES THE REHEAT STOP AND INTERCEPT VALVES

5 SHAFT ROTATION IS CLOCKWISE WHEN VIEWED FROM COLLECTOR END OF GENERATOR

6 LOAD VALUES SHOWN ARE FOR TURBINE-GENERATOR UNIT ONLY ADDITIONAL LOAD CONTRIBUTED BY CONDENSER NOT INCLUDED

7 DISTANCE REQUIRED TO REMOVE MAJOR PARTS - NOT INCLUDING SLINGS

A GENERATOR STATOR - 14 FT 3 FROM TB-GEN BASE LINE WITHOUT TERMINAL BOX ATTACHED
B GENERATOR COOLERS - 19 FT 0 IN HORIZONTALLY FROM VERTICAL ℄ OF GEN.

8 THIS OUTLINE SHALL NOT BE USED FOR CONSTRUCTION PURPOSES. THE GENERAL EQUIPMENT ARRANGEMENT, DIMENSIONS AND LOADINGS ARE TO BE CONSIDERED PRELIMINARY AND SUBJECT TO LATER MODIFICATION.

9 RECOMMENDED MINIMUM CRANE HOOK HEIGHT ABOVE TB. GEN. BASE LINE - 33 FT 7 IN

10 RECOMMENDED MINIMUM FOUNDATION HEIGHT - 40 FT 0 IN

11 THE HORIZONTAL FORCES ACTING AT THE KEYS INCLUDE A SEISMIC FACTOR OF 0.128.

PRELIMINARY OUTLINE
STEAM TURBINE - GENERATOR UNIT
TC4F - 33.5" lsb

Figure 6. Steam Turbine-Generator, Preliminary Outline

The heat to the steam cycle at 100 percent operating conditions would be 6867.4 MBtu/hr. The heat input would be 8375.54 Btu/kWh at the generator.

Stack Gas Scrubber System

Although all elements of the wet gas scrubber system would be furnished as balance-of-plant equipment, the unique aspects of this system command that it rank as a major cycle component and that it receive detailed attention.

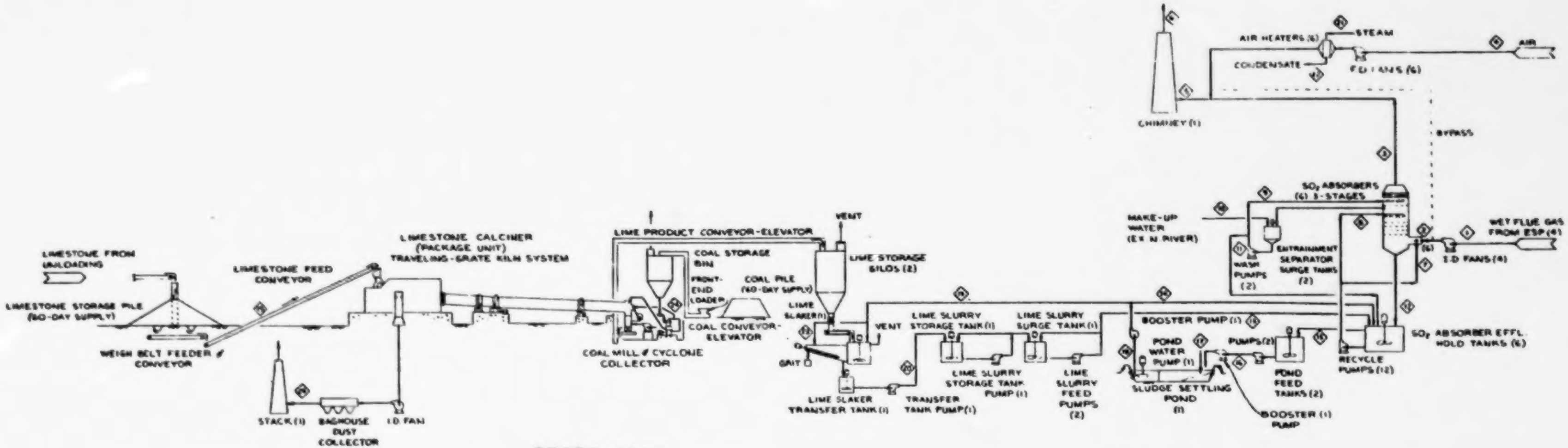
The entire scrubber system is illustrated in Figure 7 along with process flow charts appropriate for operation at the specified 5 percent flow margin, using 4.5 percent sulfur coal. The sulfur capture would be 90 percent. The two process flow charts do not differ in respect to the sulfur capture system; only the reheating of stack gas to 250 F in the upper chart and 175 F in the lower chart are different.

The lime requirement is met by calcining limestone in a rotary kiln fired with coal. There would be onsite a 60 day supply of limestone. The coal would be stacked in a four-day storage bin by front-end loaders. The emission requirements for the calciner are met by the use of a baghouse dust collector and a separate stack. No reduction in sulfur gases is expected for the coal fired in the calciner.

The lime product is expected to be in excess of 95 percent available lime. It is stored in silos with a capacity sufficient for five days' operation. With the 1500 tons per day of limestone calcining capacity, this part of the plant need not operate continuously to support plant operations. There should be sufficient time to accomplish all usual maintenance and refurbishment on a scheduled basis. The entire left half of Figure 7 represents onsite capital investment and operations that would be eliminated if lime rather than limestone were available for purchase in suitable quantities at a suitable price.

The right half of Figure 7 is the scrubbing system that causes lime to react with sulfur in the flue gas to form solids that accumulate in the sludge ponds. The lime replenishment is slaked with pond recycle water to a 16 hour storage tank. The slaked lime and remaining pond recycle water are discharged to the SO_2 absorber effluent holding tanks. Table 4 presents the major parameters of the limestone/lime system considered to this point.

The 3-stage SO_2 absorbers operate on flue gas that has been quenched from 300 F and saturated with water vapor at 125 F by the presaturation sprays at each absorber gas inlet. The flue gas then flows upward through the three absorber stages, each of which comprises a 6-inch bed of spheres. The liquid-to-gas ratio maintains 110 percent of lime-to-sulfur stoichiometric ratio. The effluent wet gas is further washed in the mist eliminator sprays. These sprays receive all of the fresh makeup water intended for all replenishment of the scrubber system. This final wash captures carryover or large droplets of drift of recycle wash liquids. Table 5 indentifies the parameters of the wet absorber system and keys the stream functions to Figure 7.


LIMESTONE FROM UNLOADING
LIMESTONE STORAGE PILE (60-DAY SUPPLY)
WEIGH BELT FEEDER & CONVEYOR
LIMESTONE FEED CONVEYOR
LIMESTONE CALCINER (PACKAGE UNIT) TRAVELING-GRATE KILN SYSTEM
STACK (1)
BAGHOUSE DUST COLLECTOR
I.D. FAN
LIME PRODUCT CONVEYOR-ELEVATOR
COAL STORAGE BIN
FRONT-END LOADER
COAL PILE (60-DAY SUPPLY)
COAL CONVEYOR-ELEVATOR
COAL MILL & CYCLONE COLLECTOR
VENT
LIME STORAGE SILOS (2)
LIME SLAKER (1)
GRIT
LIME SLAKER TRANSFER TANK (1)
TRANSFER TANK PUMP (1)
VENT
LIME SLURRY STORAGE TANK (1)
LIME SLURRY STORAGE TANK PUMP (1)
LIME SLURRY SURGE TANK (1)
LIME SLURRY FEED PUMPS (2)
BOOSTER PUMP (1)
POND WATER PUMP (1)
SLUDGE SETTLING POND (1)
PUMPS (2)
POND FEED TANKS (2)
BOOSTER (1) PUMP
MAKE-UP WATER (EX N RIVER)
WASH PUMPS (2)
ENTRAINMENT SEPARATOR SURGE TANKS (2)
SO2 ABSORBERS (6) 3-STAGES
RECYCLE PUMPS (12)
SO2 ABSORBER EFFL. HOLD TANKS (6)
I.D. FANS (4)
WET FLUE GAS FROM ESP (4)
CHIMNEY (1)
BYPASS
AIR HEATERS (6)
STEAM
CONDENSATE
F.D. FANS (6)
AIR

250°F CASE

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
DESCRIPTION	GAS TO I.D. FAN	GAS TO ABSORBER	GAS TO REHEAT	AIR TO HEATERS	GAS TO STACK	GAS TO ATMOSPHERE	SLURRY TO PRE SAT'R	RECYCLE SLURRY TO ABS	MIST ELIM RECYCLE WASH	RAW MAKE-UP WATER	ENTR SEPR BLEED-OFF	SLURRY TO SAE HT	LIME SLURRY TO SAE HT	POND WATER TO SAE HT	SAE HT OVERFLOW	USED SLURRY TO POND	SETTLED USED SLURRY	RECYCLE POND WATER	SLAKE & DILN WATER	LIME SLURRY TRANSFER	STEAM TO AIR HEATER	CONDEN-SATE RTN	LIME TO SLAKER	COAL TO CALINER	LIMESTONE TO CALINER	GAS TO STACK
M LBS./HR	8,178.5	1,363	1,3875	2,431	22,911	22,911	386.8	11,567	720	229.6	76.5	11,930	66.8	121.2	240.7	722	375.5	1,069	341.8	400.8	160.5	962.8	62.5	14.5	125	203
M ACFM (GPM)	2,664	423	841	551	6,822		(730)	(21,825)	(1,440)	(459)	(153)	(22,508)	(118)	(242)	(454)	(1,362)	(573)	(2,138)	(683)	(709)	(321)	(1926)				74.3
TEMPERATURE, °F	300	312	125	59	250																620	356				500
PRESSURE, IN. WG (PSIG)	-15	10	1	0	0	0															(130.3)	(130.3)				
PARTICULATES, LBS/HR	723	723	3,170		4,338	4,338																				<15
SULFUR DIOXIDE, LBS/HR	67,800	11,300	1,130		6,780	6,780																				<150
UNDISSOLVED SOLIDS, %							10	10				10	20		10	10	40			20						
SPECIFIC GRAVITY							1.06	1.06	1.0	1.0	1.0	1.06	1.13	1.0	1.06	1.06	1.31	1.0	1.0	1.13						
M LBS/HR TOTAL	8,178.5	8,178.5	8,815	14,986	22,911	22,911	2,821	69,402	4,320	459.1	459.1	11,578	400.8	727.2	1444	1444	375.5	1,069	341.8	400.8	962.8	962.8	62.5	14.5	125	203

175°F CASE

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
DESCRIPTION	GAS TO I.D. FAN	GAS TO ABSORBER	GAS TO REHEAT	AIR TO HEATERS	GAS TO STACK	GAS TO ATMOSPHERE	SLURRY TO PRE SAT'R	RECYCLE SLURRY TO ABS	MIST ELIM RECYCLE WASH	RAW MAKE-UP WATER	ENTR SEPR BLEED-OFF	SLURRY TO SAE HT	LIME SLURRY TO SAE HT	POND WATER TO SAE HT	SAE HT OVERFLOW	USED SLURRY TO POND	SETTLED USED SLURRY	RECYCLE POND WATER	SLAKE & DILN WATER	LIME SLURRY TRANSFER	STEAM TO AIR HEATER	CONDEN-SATE RTN	LIME TO SLAKER	COAL TO CALINER	LIMESTONE TO CALINER	GAS TO STACK
M LBS./HR	8,178.5	1,363	1,3875	844.6	11,692	11,692	386.8	11,567	720	229.6	76.5	11,930	66.8	121.2	240.7	722	375.5	1,069	341.8	(400.8)	95.6	213.4	62.5	14.5	125	203
M ACFM (GPM)	2,644	423	841	128	3,095		(730)	(21,825)	(1,440)	(459)	(153)	(22,508)	(118)	(242)	(454)	(1,362)	(573)	(2,138)	(683)	(709)	(71)	(427)				74.3
TEMPERATURE, °F	300	312	125	59	175																620	356				500
PRESSURE, IN. WG (PSIG)	-15	10	1	0	0	0															(130.3)	(130.3)				
PARTICULATES, LBS/HR	723	723	3,170		4,338	4,338																				<15
SULFUR DIOXIDE, LBS/HR	67,800	11,300	1,130		6,780	6,780																				<150
UNDISSOLVED SOLIDS, %							10	10				10	20		10	10	40			20						
SPECIFIC GRAVITY							1.06	1.06	1.0	1.0	1.0	1.06	1.13	1.0	1.06	1.06	1.31	1.0	1.0	1.13						
M LBS./HR TOTAL	8,178.5	8,178.6	8,825	5,867	11,692	11,692	2,821	69,402	4,520	459.1	459.1	11,578	400.8	727.2	1,444	1,444	375.5	1,069	341.8	400.8	213.4	215.4	62.5	14.5	125	203

REVISED TABLE
ISSUED FOR REPORT

BECHTEL
SAN FRANCISCO

GE/NASA
ADVANCED ENERGY CONVERSION STUDY

PROCESS FLOW DIAGRAM
WET STACK GAS SCRUBBER 250°

11107 | P-606 | 1

REVISED TABLE
ISSUED FOR REPORT

BECHTEL
SAN FRANCISCO

GE/NASA
ADVANCED ENERGY CONVERSION STUDY

PROCESS FLOW DIAGRAM
WET STACK GAS SCRUBBER

11107 | P-610 | 1

Figure 7. Process Flow Diagram

Table 4

LIMESTONE/LIME SYSTEM PARAMETERS
CONVENTIONAL FURNACE-STEAM CYCLE

Lime Product Quality	95% Available CaO
Limestone/Lime Product	2 Tons/Ton
Limestone Storage	60-Day Supply 90,000 Tons
Limestone Calciner (Traveling Grate Kiln)	
Nominal Production	650 Tons/Day
Capacity	880 Tons/Day
Fuel Requirements (Ill. #6)	5 MBtu/Ton Lime
Lime Storage Capacity	5-Day Supply
Lime Slaker Capacity	800 Tons/Day
Slaking Temperature	$\sim$190 F
Slaked Lime Slurry Solids (After Dilution)	20% WT
Lime Slurry Surge Capacity	16 Hours

Table 5

WET LIME ABSORBER SYSTEM PARAMETERS
CONVENTIONAL FURNACE-STEAM CYCLE
(BASIS: 90% SO_x REMOVAL FOR 4.5% SULFUR COAL)

SO_2 ABSORBERS (6)	TCA-Type
No. of Stages	3 (6" of Spheres/Stage)
Superficial Gas Velocity	8 FT/S
Total Pressure Drop	9-IN. H_2O
Liquid/Gas Ratio 8	72 GAL/MSCF
Presaturation Sprays 7	2.5 GAL/MSCF
Mist Eliminator Wash Sprays 9	2 GPM/FT^2
Lime: SO_2 Stoic. Ratio	110%
Absorber Hold Tank Residence Time	5 Min.
Recycle Slurry Solids 15 8 7	10% WT
Lime Makeup Slurry Solids 13	20% WT
Spent Slurry Pond Solids 17	40% WT

Stream Identification, Figure 7

The flue gas at 125 F and saturated with water vapor is highly corrosive and chemically active. Normal heat exchangers that would reheat the flue gas to an appropriate stack temperature would not withstand the chemical attack of the flue gas. Even the flues and stack must be lined to avoid attack. The necessary stack temperature is achieved by steam-heating additional air and blending the heated air with the flue gas. This requires six low head fans and six heaters. Two alternatives of stack temperature were examined: 250 F and 175 F. Table 6 presents the parameters of the blend air and its heat requirements for these alternatives at their 100 percent operating point. The blending means of gas heating is increasingly inefficient as the stack temperature is increased toward the air temperature of 333 F, accounting for the great differences between these two alternatives.

The wet gas scrubber arrangement shown in Figure 8 connects these several elements with the four induced draft fans that service the four electrostatic precipitators. There is a total of six absorber and stack reheater trains. The induced draft fans feed a cross-duct that is normally isolated by dampers from the startup bypass path. Connecting in a downward fan-like duct are the presaturation spray ducts to each absorber. The redundancy dictated by the size of the absorbers should produce a high level of availability for the scrubber system.

The sludge ponds are the remaining element of the wet scrubber system. Each pond would measure 3600 feet by 3600 feet by 22 feet deep. Six ponds would accommodate 30 years of plant operations. Only one pond was accounted for in the capital cost presentation. The accumulation rate of solids would equal the solids delivery rate of 150,000 lb/h of calcium sulfite and excess unreacted lime. Because water would accumulate at a rate 50 percent greater, in situ solids concentration would be 40 percent. It is important to recognize these two accumulations, because the tables on Figure 7 represent steady-state balances for the absorbers but nonsteady states for lime, makeup water, and sludge accumulation.

Scrubber Costs

The direct costs for the scrubber system comprise material costs and direct field labor costs as detailed in Table 7 for a 250 F stack and in Table 8 for a 175 F stack. These costs are insufficient insofar as balance of plant construction must bear a prorated share of the indirect field expenses and additional electrical, civil, process, and yardwork must be done. Tables 9 and 10 present the complete costs, with the first two items on line 1.0 carried over from Tables 7 and 8. The allocations for indirect labor, fees, contingency, and escalation will be discussed in the subsection concerned with balance of plant in Section 5, "System Performance and Cost." All of these items of expense will also be included in the comprehensive list of balance-of-plant accounts. Presentation here with all elements of costing is done to facilitate identification of the incremental cost due to the wet scrubber system. For the 250 F stack case, a total of $51.9 million for this major system is comparable to a steam turbine-generator cost of $26 million, and a boiler component cost of $39.7 million. The wet scrubber is a major addition.

Table 6

FLUE GAS HEATERS
FOR WET SCRUBBER SYSTEMS

	STACK GAS REHEAT TEMPERATURE	
PARAMETER	250 F	175 F
Heat Duty, MBtu/HR	971	217
Steam	620 → 356 F	620 → 356 F
Air	333 ← 59 F	333 ← 59 F
Air Velocity, FT/MIN	900	900
Air Rate, M LB/HR	14.586	3.267
Pressure Drop, IN. H_2O	1.5	1.0
Heat Transfer Rate, Btu/(HR SQ FT °F)	5.5	10.4
Finned Surface, SQ FT	645,000	86,500

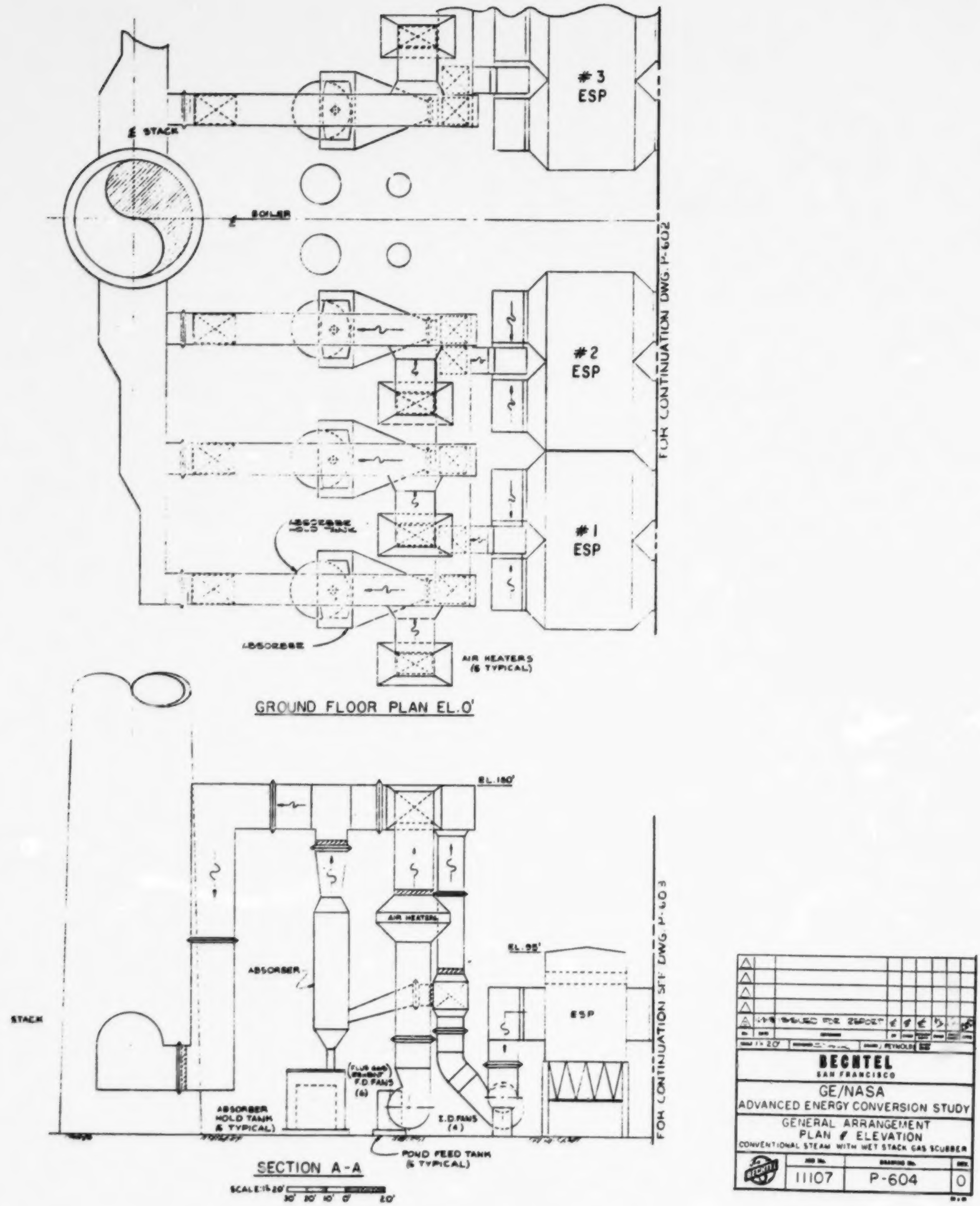

#3 ESP
℄ STACK
℄ BOILER
FOR CONTINUATION DWG. P-602
#2 ESP
#1 ESP
ABSORBER HOLD TANK
ABSORBER
AIR HEATERS (6 TYPICAL)
GROUND FLOOR PLAN EL.0'
EL.180'
AIR HEATERS
EL.95'
ABSORBER
STACK
ESP
FOR CONTINUATION SEE DWG. P-603
FLUE GAS F.D FANS (6)
I.D FANS (4)
ABSORBER HOLD TANK (6 TYPICAL)
POND FEED TANK (6 TYPICAL)
SECTION A-A
SCALE: 1"=20'
30' 20' 10' 0' 20'
ISSUED FOR REPORT
1"=20'
REYNOLDS
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
GENERAL ARRANGEMENT
PLAN & ELEVATION
CONVENTIONAL STEAM WITH WET STACK GAS SCUBBER
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Figure 8. Wet Gas Scrubber Arrangement—Conventional Steam Plant

]

TABLE 7

SCRUBBER EQUIPMENT DIRECT FIELD COSTS
(250 STACK TEMP.)

Major Mechanical Equipment	Materials M$	Direct Labor M$	Total M$
Limestone Handling	1.25	0.25	1.50
Limestone/Lime System	3.66	0.78	4.44
SO_2 Scrubber Vessels	6.93	1.01	7.94
Scrubber System Pumps	1.08	0.12	1.20
Scrubber System Tanks	2.18	0.05	2.23
Scrubber Ductwork	3.27	2.43	5.70
Scrubber Flue Gas Equipment	3.09	0.32	3.41
TOTAL	21.46	4.96	26.42

TABLE 8

SCRUBBER EQUIPMENT DIRECT FIELD COSTS
(175 STACK TEMP.)

Major Mechanical Equipment		Materials M$	Direct Labor M$	Total M$
Limestone Handling		1.25	0.25	1.50
Limestone/Lime System		3.66	0.78	4.44
SO_2 Scrubber Vessels		6.93	1.01	7.94
Scrubber System Pumps		1.08	0.12	1.20
Scrubber System Tanks		2.18	0.05	2.23
Scrubber Ductwork	*	1.95	1.41	3.36
Scrubber Flue Gas Equipment	*	0.90	0.08	0.98
TOTAL	*	17.95	3.70	21.65

*Changed From 250 Stack Case

TABLE 9

WET LIME SCRUBBER CAPITAL COST BREAKDOWN
CONVENTIONAL FURNACE - STEAM CYCLE
(250 F STACK TEMP.)

Categories	Materials M$	Direct Labor M$	Indirect Field M$	Total M$
1.0 Process Mechanical Equipment (Limestone Handling, Lime System, Absorbers, Tanks, Pumps, Air Heaters, F.D. Fans, Ductwork)	21.5	5.0	4.5	31.0
2.0 Electrical	0.7	0.9	0.8	2.4
3.0 Civil and Structural	3.7	2.1	1.8	7.6
4.0 Process Piping and Instrumentation	4.3	2.6	2.3	9.2
5.0 Yardwork and Miscellaneous	-	0.9	0.8	1.7
				51.9
A/E Engineering, Home Office & Fee @ 15%				7.8
Total Plant Cost				59.7
Contingency @ 20%				11.9
Total Capital Cost				71.6
Escalation & Interest During Construction				39.2
Total Plant Investment				110.8

TABLE 10

WET LIME SCRUBBER CAPITAL COST BREAKDOWN
CONVENTIONAL FURNACE - STEAM CYCLE
(175 F STACK TEMP.)

Categories	Materials M$	Direct Labor M$	Indirect Field M$	Total M$
1.0 Process Mechanical Equipment (Limestone Handling, Lime System, Absorbers, Tanks, Pumps, Air Heaters, F.D. Fans, Ductwork)	17.95	3.7	3.3	25.0
2.0 Electrical	0.7	0.9	0.8	2.4
3.0 Civil and Structural	3.7	2.1	1.8	7.6
4.0 Process Piping and Instrumentation	3.8	2.5	2.2	8.5
5.0 Yardwork and Miscellaneous	-	0.9	0.8	1.7
				45.2
A/E Engineering, Home Office & Fee @ 15%				6.8
Total Plant Cost				52.0
Contingency @ 20%				10.4
Total Capital Cost				62.4
Escalation & Interest During Construction				34.2
Total Plant Investment				96.6

4. PLANT ARRANGEMENT

A group of plant arrangement drawings were prepared by the architect-engineer as a preliminary step to evaluating construction costs.

Plot Plan

The plant plot arrangement is based on receiving coal and limestone by rail and shipping fly ash offsite by rail. A 60 day pile of coal and limestone is provided. Silos to hold 15 days' accumulation of dry fly ash are provided adjacent to the rail terminal. A series of small ponds catch runoff water from the site and provide for treatment of all water returned to the North River.

Figure 9 shows the plot arrangement. The smaller overall plot layout indicates the dominant aspect of one 3600 foot by 3600 foot sludge pond. The upper detail shows that at the active site half the area will be used for coal storage and for cooling towers. The boiler house abuts the turbine building. The electrostatic precipitators are of substantial size in order to achieve 98.6 percent particle removal. A single stack serves the entire plant. The land area for the power generation plant is 92 acres; the sludge ponds must agregate an additional 1785 acres in close proximity to the main plant. A total area of 3 square miles will be required. This requirement will severely constrain the siting opportunities for these plants.

The coal feed system provides transportation by belt conveyor from the line storage pile to the transfer tower. Tramp iron is removed and large size frozen coal is crushed to small size. Next, the coal is conveyed to the surge bin in the boiler house, where vibrating feeders and two conveyor belts feed eight coal silos disposed on opposite sides of the building. The filled silos guarantee 8 hours of boiler output. Each silo feeds a single coal pulverizer by a gravimetric feed. Coal drying and conveyance to the burners is by hot primary air. For startup and warmup an oil system firing No. 2 fuel oil is provided, along with 100,000 gallons of fuel storage in two tanks.

General Arrangement

A more detailed general arrangement plan for the turbine hall and boiler is presented in Figure 10. The eight silos on either side of the boiler each hold an 8 hour coal supply, and all feed to one coal pulverizer. The air preheaters and flues to the electrostatic precipitators of Figure 8 dominate the leftside. The ground level of the turbine hall on the right indicates the arrangement of the many support functions for the steam turbine cycle.

The general arrangement elevation view shown in Figure 11 combines the boiler details of Figures 3 and 4 in a proper orientation to the turbine hall and the flue gas exhaust system detailed in Figure 8. The arrangement provides short steam lines and liberal access space for all apparatus. At the extreme left, the gas enters the flue gas system of Figure 8 at the electrostatic precipitators.

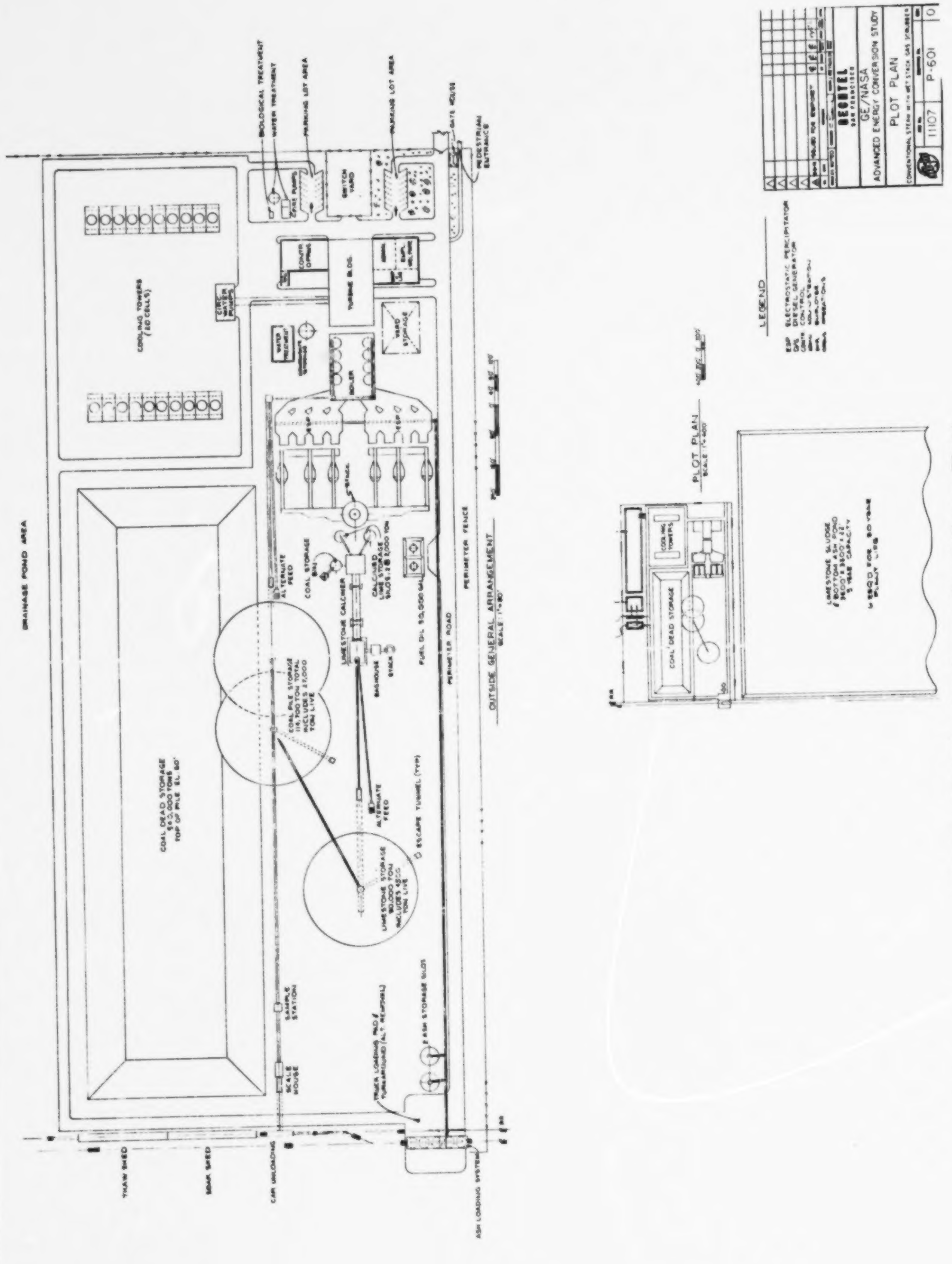
DRAINAGE POND AREA
THAW SHED
SOAK SHED
CAR UNLOADING
ASH LOADING SYSTEM
SCALE HOUSE
SAMPLE STATION
COAL DEAD STORAGE 562,000 TONS TOP OF PILE EL 60'
COAL PILE STORAGE 116,700 TON TOTAL INCLUDES 27,000 TON LIVE
LIMESTONE STORAGE 80,000 TON INCLUDES 4300 TON LIVE
ESCAPE TUNNEL (TYP)
ALTERNATE FEED
TRUCK LOADING PAD & TURNAROUND (ALT. REMOVAL)
ASH STORAGE SILOS
BAGHOUSE
STACK
LIMESTONE CALCINER
FUEL OIL 50,000 GAL
COAL STORAGE BIN
CALCINED LIME STORAGE SILOS 2 @ 2300 TON
PERIMETER ROAD
PERIMETER FENCE
OUTSIDE GENERAL ARRANGEMENT
ESP
BOILER
WATER TREATMENT
YARD STORAGE
TURBINE BLDG.
CONTR.
COOLING TOWERS (20 CELLS)
CIRC. WATER PUMPS
SWITCH YARD
FIRE PUMPS
BIOLOGICAL TREATMENT
WATER TREATMENT
PARKING LOT AREA
PARKING LOT AREA
GATE HOUSE
PEDESTRIAN ENTRANCE
PLOT PLAN
COOLING TOWERS
COAL DEAD STORAGE
LIMESTONE SLUDGE & BOTTOM ASH POND
RESERVED FOR 30 YEAR PLANT LIFE
LEGEND
ESP ELECTROSTATIC PRECIPITATOR
DIESEL GENERATOR
CONTROL
BECHTEL SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
PLOT PLAN
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Figure 9. Plot Plan for Conventional Steam Plant

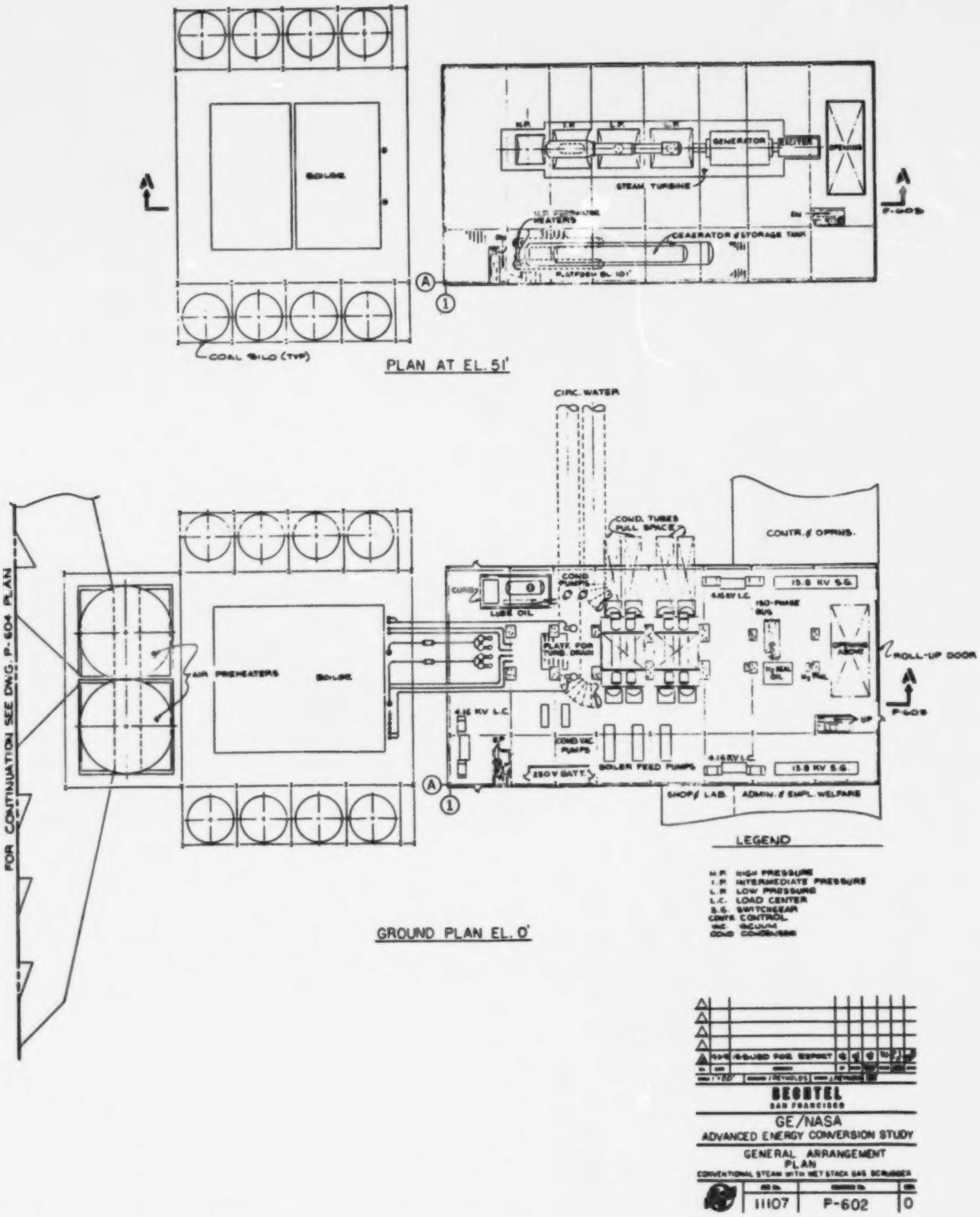
BOILER
STEAM TURBINE
GENERATOR
EXCITER
OPENING
H.P. FEEDWATER HEATERS
DEAERATOR & STORAGE TANK
PLATFORM EL. 101'
P-605
A
1
COAL SILO (TYP)
PLAN AT EL. 51'
CIRC. WATER
COND. TUBES PULL SPACE
CONTR. & OPRNS.
COND PUMPS
CURB
LUBE OIL
PLATF. FOR TURB. DRAIN
4.16 KV L.C.
13.8 KV S.G.
ISO-PHASE BUS
H_2 SEAL OIL
H_2 PNL.
OPENING ABOVE
ROLL-UP DOOR
UP
COND VAC PUMPS
BOILER FEED PUMPS
250 V BATT.
SHOP & LAB.
ADMIN. & EMPL. WELFARE
AIR PREHEATERS
FOR CONTINUATION SEE DWG. P-604 PLAN
GROUND PLAN EL. 0'
LEGEND
H.P. HIGH PRESSURE
I.P. INTERMEDIATE PRESSURE
L.P. LOW PRESSURE
L.C. LOAD CENTER
S.G. SWITCHGEAR
CONTR. CONTROL
VAC. VACUUM
COND. CONDENSER
ISSUED FOR REPORT
1" = 50'
J. REYNOLDS
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
GENERAL ARRANGEMENT PLAN
CONVENTIONAL STEAM WITH WET STACK GAS SCRUBBER
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Figure 10. Turbine and Boiler Buildings

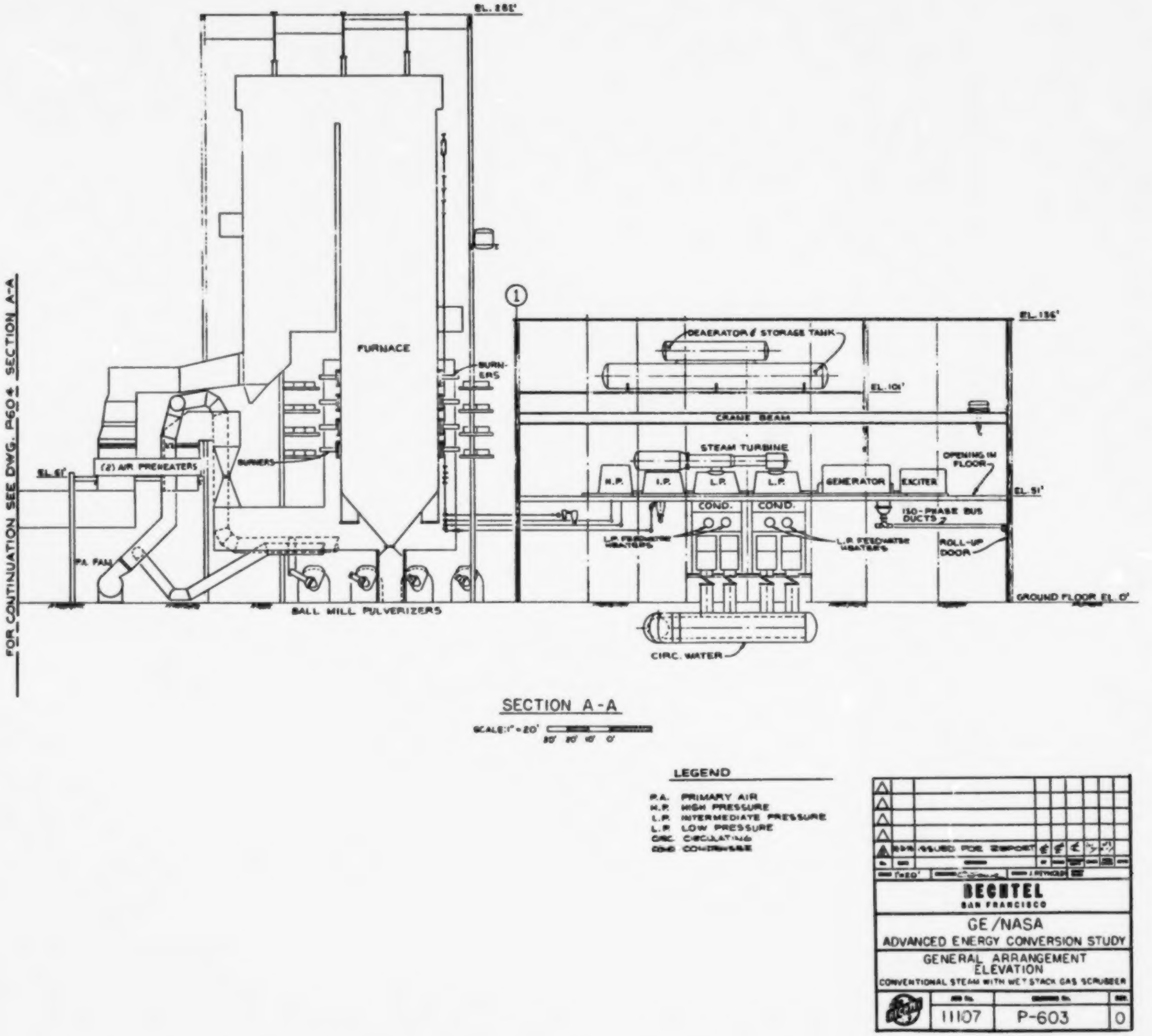
EL. 261'
FOR CONTINUATION SEE DWG. P604 SECTION A-A
EL. 61'
(2) AIR PREHEATERS
P.A. FAN
BURNERS
FURNACE
BURN-ERS
BALL MILL PULVERIZERS
①
EL. 136'
DEAERATOR & STORAGE TANK
EL. 101'
CRANE BEAM
STEAM TURBINE
H.P.
I.P.
L.P.
L.P.
COND.
COND.
GENERATOR
EXCITER
OPENING IN FLOOR
EL. 51'
ISO-PHASE BUS DUCTS
L.P. FEEDWATER HEATERS
L.P. FEEDWATER HEATERS
ROLL-UP DOOR
GROUND FLOOR EL. 0'
CIRC. WATER
SECTION A-A
SCALE: 1" = 20'
30' 20' 10' 0'
LEGEND
P.A. PRIMARY AIR
H.P. HIGH PRESSURE
I.P. INTERMEDIATE PRESSURE
L.P. LOW PRESSURE
CIRC. CIRCULATING
COND. CONDENSATE
ISSUED FOR REPORT
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
GENERAL ARRANGEMENT
ELEVATION
CONVENTIONAL STEAM WITH WET STACK GAS SCRUBBER
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Figure 11. Elevation View of General Arrangement

The four electrostatic precipitators shown in Figure 8 are especially voluminous, to provide the low gas velocities essential to the capture of 98.6 percent of the entrained fly ash. Each unit is 54 feet high, 93 feet wide, and 44 feet deep. The entry and exits are divided in two to retain normal flue connections. Each unit is serviced by one induced draft fan working in the cleaned gas leaving the unit. The six wet gas scrubbers and reheaters then deliver the flue gas to a single 500 foot stack.

Electrical Schematic

Figure 12 is a single-line diagram showing major electrical equipment. The single steam turbine-generator at 24 kV feeds two main transformers to 500 kV and two auxiliary transformers to 13.8 kV. A startup transformer may also feed the 13.8 kV bus from the 500 kV transmission line. Major and subsidiary buses are identified, as well as major auxiliary electrical loads.

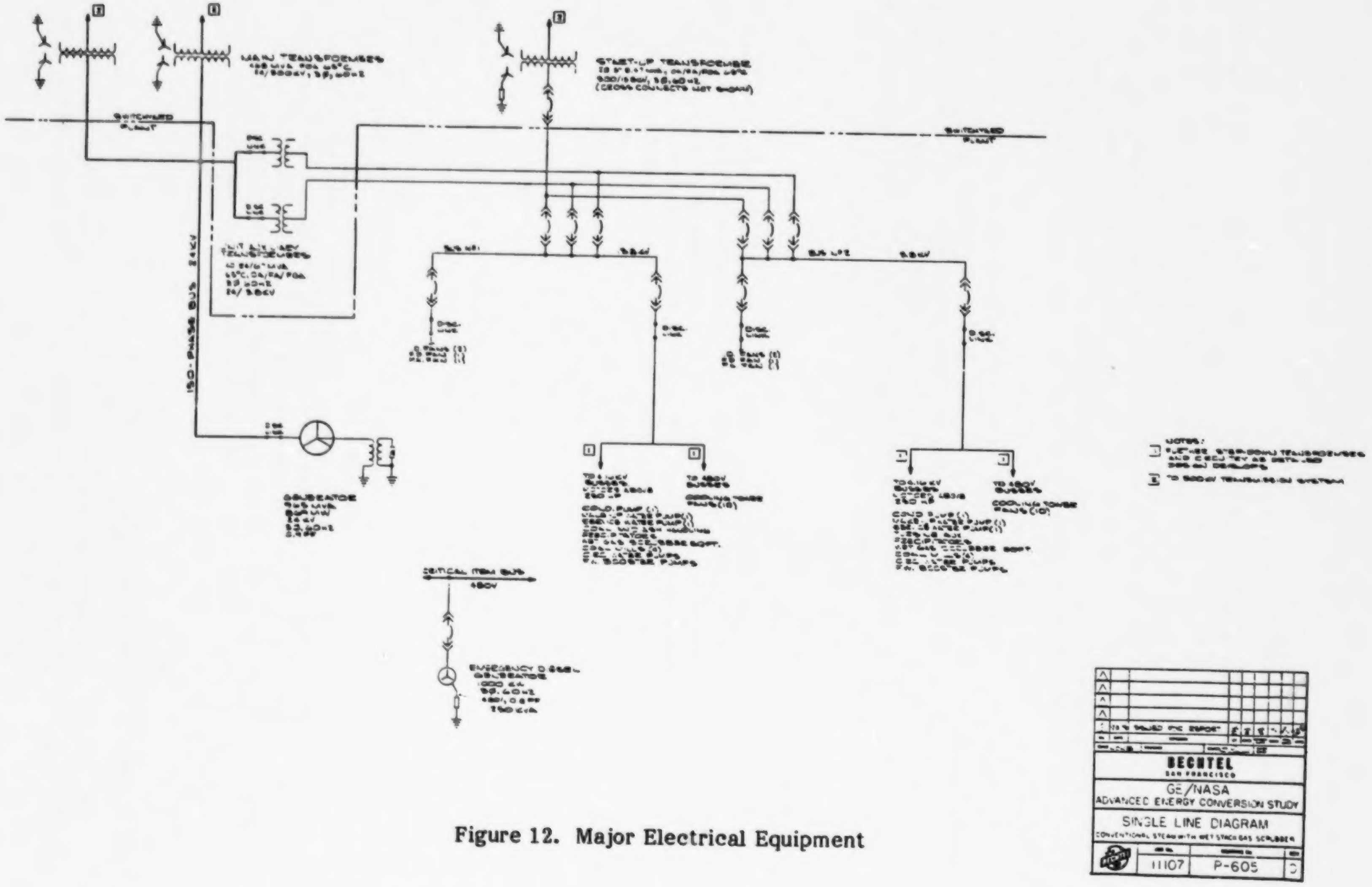
MAIN TRANSFORMERS
START-UP TRANSFORMER
(CROSS CONNECTS NOT SHOWN)
SWITCHYARD PLANT
UNIT AUXILIARY TRANSFORMERS
ISO-PHASE BUS 24KV
DISC. LINK
GENERATOR
TO 480V BUSSES
COOLING TOWER FANS (10)
CRITICAL ITEM BUS
480V
EMERGENCY DIESEL GENERATOR
NOTES:
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
SINGLE LINE DIAGRAM
CONVENTIONAL STEAM WITH WET STACK GAS SCRUBBER
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Figure 12. Major Electrical Equipment

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5. SYSTEM PERFORMANCE AND COST

Performance Integration

Evaluation was made of plant performance on the average 59 F day with all equipment operating at 100 percent condition with respect to its design and specification point. To adjust performance data so that a perfect integration results, a detailed steam turbine heat balance had been made at the 100 percent operating point, as presented in Figure 5. The required 6867.4 MBtu/h from the boiler were deemed to be provided at the exact boiler efficiency (87.1346) that prevails with the 5 percent margin condition detailed in the boiler heat balance (Figure 4). Typically, boiler efficiency improves slightly at reduced firing rates.

In addition to the coal fired at the boiler, the rate of coal usage for calcining was evaluated, on the basis that the mass flows of the wet gas scrubber process flow diagram (Figure 7) represent operation at a 5 percent margin above the required 100 percent level. Table 11 presents the basis and results for the integration into the steam cycle of boiler and wet gas scrubber operating flow rates.

System Output

For the 100 percent operating point Table 12 shows that the 820 MW of generator output was reduced to 747 MW net plant output by the 73 MW required for auxiliaries. The auxiliary loss breakdown is presented in Table 13. The induced fan power requirement was 4 MW greater than normal as a result of the additional 9 inch drop in water pressure in the wet gas scrubbers; the scrubber system itself consumes 10 MW. All other values are typical of steam plants. These auxiliary loads consume 8.9 percent of the generator output in the plant.

Costs-General

Costs were synthesized from the costs of major components, balance of plant materials, and balance of plant labor. An equipment list of major items in the balance of plant was made to assure completeness and to assure that the selected equipment ratings would match the extreme requirements for continuous operation. A detailed breakdown of balance of plant direct labor in man-hours and of material costs completes the identification of all items of construction and installation costs. To these are added indirect field labor costs and major component costs. An architect-engineering fee is added in proportion to the engineering effort. To the sum total a contingency is applied, to be expanded on items not counted in a preliminary appraisal such as this. Finally, a factor of 0.548 is added to the total for escalation and interest during construction for the 5.5 year period.

Major Component Characteristics

The steam generator characteristics are listed in Table 14. The heat-delivered efficiency of 87.1 percent would improve approximately 1.2 percent

Table 11

ENERGY BALANCE--100 PERCENT RATING, 59 F DAY
CONVENTIONAL STEAM PLANT--WET SCRUBBERS--250 F STACK

PARAMETER	VALUE	
Generated Power	819938	kW
Heat-to-Steam Cycle[1]	6867.4	MBtu/Hr
HHV of Fuel Fired[2]	7881.4	MBtu/Hr
Coal Fired at Boiler[3]	730570	pph
Coal Fired at Calciner[4]	13810	pph
Total Coal Rate	744380	pph
Effective Boiler Efficiency	85.52	percent
Limestone Feed Rate[4]	119050	pph
Scrubber Makeup Water Rate	917	gpm

Notes:
1 From 100 percent steam cycle heat balance, Figure 5
2 Boiler Efficiency 0.871346 from heat balance, Figure 4
3 Based on 10788 Btu/pound higher heating value (HHV)
4 Rates proportioned 1/1.05 for wet scrubber, Figure 7

Table 12

SYSTEM OUTPUT
CONVENTIONAL STEAM PLANT-WET SCRUBBERS-250 F STACK

Steam Cycle Output	819.9 MW
Total Auxiliary Losses	72.7 MW
Net Power Plant Output (60 Hz AC-500kV)	747.2 MW

Table 13

AUXILIARY LOSS BREAKDOWN
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-250 F STACK

ITEM	ASSUMPTIONS	NO. OF UNITS	TOTAL MW_e
Furnace			
FD Fans	19" Δ P, 0.82 EFF	4	7.3
PA Fans	42" Δ P, 0.82 EFF	4	2.9
ID Fans	23" Δ P, 0.78 EFF	4	8.8
ESP	695,000 CFM, 300 F, 0.986 EFF	4	5.2
Pulverizers		8	7.6
			31.8
Turbine Auxiliary	0.33% of Gross kW	1	2.8
Wet Scrubber			10.0
Major Pumps			
Booster	600 PSI, 6 Million #, 75% x 90%	2	3.7
Condensate	185 PSI, 3.9 Million #, 70% x 90%	2	1.0
Circ. Water	Proportion to Cooling Heat Duty	3	4.8
			9.5
Water Intake	A/E Estimate	2	0.9
Solids Handling	Based on Rates and Lifts	1	3.0
"Hotel" Loads	A/E Estimate 1% of Generation	1	8.3
Cooling Tower Fans	Proportional to Heat Duty	20	2.3
Transformers	0.5% of Gross Generation	4	4.1
		TOTAL AUXILIARY POWER =	72.7

if the flue gas were reduced in temperature to 250 F rather than the 300 F level dictated by the high level of sulfur in the fuel. The radiant surfaces in the furnace experience a heat flux four times the average, while the more extensive convection surfaces experience two-thirds the average heat flux.

The cost of $39.73 million (mid 1975) includes the air preheater, flues and ducts, coal pulverizers, and supporting steel and platforms. Excluded are the cost of the fans which appear as balance of plant, and the 6.15 million dollar cost of the electrostatic precipitators with their support steel.

Table 15 shows the cost of the steam turbine-generator at $26 million and expresses the cost per pound and per unit of energy concerned.

Major Component and Subsystem Capital Cost

A more detailed comparison of ultimate costs can be made by including the balance of plant materials and direct and indirect labor costs. Table 16 shows such a comparison. The conventional steam generator with the coal and solids handling aggregate $85 million; the gas cleanup comprising electrostatic precipitators and wet lime scrubber subsystem total $60 million. The steam turbine generator is of the order of $30 million.

It is evident that comparisons based on component costs alone would give proportions totally different from that for the totally installed item. Balance of plant equipment and costs merit a detailed evaluation.

Balance of Plant Equipment List

Specifications for balance of plant equipment are presented in Table 17 as prepared by the architect-engineer (Bechtel). The specifications are based on continuous operation at the valves wide open (VWO) condition for the steam turbine flow rates. The boiler and wet scrubbers have comparable margins.

The electric motor drives for pumps and fans are sized for additional margins of 10 percent on flow, 20 percent on static pressure rise, and approximately 30 percent on power. All of these specifications are for equipment more than sufficient to match the 100 percent operating condition.

Balance of Plant Capital Costs

Table 18 presents the architect-engineer's detailed breakdown of the direct manual field labor in thousands of man-hours (MH 1000's), and of balance of plant material cost in thousands of dollars ($1000's) for each major category of the balance of plant. For the reading of these data, an average hourly field labor rate of $11.75 in mid-1975 dollars is used to convert man-hours to dollars. Where indirect field labor is allocated to individual items rather than the total labor for the job, it will be apportioned as 90 percent of the direct field labor, which is equivalent to $10.58 per hour.

Table 14

HEAT EXCHANGER CHARACTERISTICS
CONVENTIONAL STEAM-WET GAS SCRUBBERS-250 F STACK

HEAT EXCHANGER	NO. OF UNITS	VESSEL SIZE OR TYPE	OUTPUT OR DUTY PER UNIT MBtu	EFFICIENCY	UNIT WEIGHT (FOB) M LB	UNIT COST (FOB) M$	SURFACE AREA FT^2	HEAT FLUX AVERAGE Btu/(HR FT^2)
Steam Generator	1	130' x 90' x 282'	6867	87.1%	40.35	39.73	610,000	11,670
							72,000*	44,745*
							538,000†	7,247†

*Radiant Furnace Surfaces
†Convection Surfaces

Table 15

MAJOR CWS COMPONENT AND SUBSYSTEM WEIGHTS AND COSTS SUMMARY-250 F STACK

MAJOR COMPONENT OR SUBSYSTEM	WEIGHT (FOB) M LBS	COMPONENT OR SUBSYSTEM COSTS (FOB) M$	OUTPUT OR DUTY	COST PER UNIT OUTPUT OR DUTY	COST PER LB
Prime Cycle					
Steam Turbine-Generator	6.5	26.0	819.9 MW_e	31.7 $/$kW_e$	4.0 $/LB
(Generator Alone)	(0.940)	--	819.9 MW_e		--
Steam Generator	40.35	39.73	2013 MW_{th}	19.74 $/$kW_{th}$	0.98 $/LB

Table 16

MAJOR COMPONENT AND SUBSYSTEM CAPITAL COST SUMMARY
CONVENTIONAL STEAM PLANT-WET SCRUBBERS-250 F STACK

MAJOR COMPONENT OR SUBSYSTEM	NO. OF UNITS	COST/UNIT (FOB) M$	COMPONENT OR SUBSYSTEM COSTS (FOB) M$	BOP MATERIALS M$	SITE LABOR (DIRECT + INDIRECT) M$	TOTAL INSTALLED COST M$
Fuel Handling & Preparation						
Coal and Solids Handling	--	--	--	10.47	3.21	13.68
Prime Cycle						
Steam Turbine-Generator	1	26.0	26.0	0.10	2.68	28.78
Conventional Steam Generator	1	39.73	39.73	8.48	23.1	71.31
Electrostatic Precipitators	4	1.54	6.15	0.22	2.34	8.71
Cooling Towers	20	--	--	3.61	3.17	6.78
Pumps, Heat Exchangers, Stacks	--	--	--	11.32	3.48	14.80
Piping, Etc.	--	--	--	14.00	22.33	36.33
Gas Cleanup System						
Wet Lime Scrubbers				30.36	21.54	51.90

Table 17 (page 1 of 4)

BALANCE-OF-PLANT EQUIPMENT LIST
CONVENTIONAL STEAM PLANT WITH WET LIME SCRUBBERS
250 F EXHAUST GAS TEMPERATURE

Eqpt. No.	Service	Description
	1.0 Coal & Limestone Handling Systems	
C-1	Coal Conveyor Belt	60 in wide, 340 ft long, 3000 tph
C-2	" " "	" " " 760 ft " " "
C-3	" " "	" " " 190 ft " " "
C-4	" " "	42 in " 980 ft " 500 tph
C-5	" " "	" " " 540 ft " " "
C-6	" " "	" " " 170 ft " " "
C-7	" " "	" " " 110 ft " " "
C-8	" " " (2 required)	30 in " 160 ft " 300 tph
C-9	Limestone Conveyor Belt	60 in " 500 ft " 3000 tph
C-10	" " "	24 in " 630 ft " 65 tph
C-11	" " "	" " " 420 ft " " "
C-12	Limestone Bucket Conveyor	" " " 120 ft " 100 tph
C-13	Traveling Grate-Kiln System (Package)	650 ton/day nominal lime production (880 ton/day design capacity), 12 ft wide x 48 ft long traveling grate, 13 ft I.D. x 180 ft long rotary kiln with Niems-type cooler. Includes coal grinding/firing equipment, control panel/instrumentation, all refractories and drives, induced draft fan, baghouse dust collector and ducting.
C-14	Coal Conveyor Belt	18 in wide, 60 ft long, 20 tph
C-15	Lime Bucket Conveyor (2 required)	24 in wide, 140 ft long, 40 tph
C-16	Fly Ash Silos (2 required)	Total Volume 833,184 ft, 80 ft dia x 85 ft high

Table 17 (page 2 of 4)

Eqpt. No.	Service	Description
	2.0 Electrical Systems	
E-1	Main Transformers (2 required)	468 MVA, FOA, 65 C, 24/500 kV
E-2	Unit Auxiliary Transformers (2 required)	40/54/67 MVA, 65 C, OA/FA/FOA, 23/13.8 kV, 30, 60Hz
E-3	Emergency Diesel Generator	1000 kW, 30, 60 Hz, 480 V, 0.8 PF
E-4	Start-up Transformer	28/37.5/47 MVA, OA/FA/FOA, 500/13.8 kV, FOA, 65C, 30, 60 Hz
E-5	Miscellaneous 480V LCC Transformers (14 required)	1689 kVA, OA, 65 C, 13.8kV/489V/277V, 30, 60 Hz
E-6	Boiler Auxiliary Transformers (2 required)	5500 kVA, OA, 65 C, 13.8/4.16 kV, 30, 60 Hz
E-7	LCC Transformers (2 required)	7000 kVA, OA, 65 C, 13.8/4.16 kV, 30, 60 Hz
E-8	Scrubber Transformers (2 required)	5000 kVA, OA, 65 C, 13.8/4.16 kV, 30, 60 Hz
	3.0 Main Fluid Systems	
F-1	Main Condenser	3.31 x 10 ft of Heat Transfer Area Std. material. In other respects same as AFB but with # of tubes scaled down in proportion to heat transfer area.
F-2	Piping:	
	Circulating Water	I.D. = 114 in
	Main Steam	I.D. = 15.3 in, tm = 3.97 in
	Boiler Feed Water	I.D. = 26.53 in, tm = 0.675 in
	Coal Reheat	I.D. = 32.54 in, tm = 1.57 in
	Hot Reheat	I.D. = 18.1 in, tm - 2.25 in

Table 17 (page 3 of 4)

Eqpt. No.	Service	Description			
F-3	Feedwater Heaters:	Shell Press/Temp. psia/ F	Tube Press/Temp. psia/ F	Flow (100%) lb/hr	Heat Transfer Area ft
	LP #1	5/163	210/158	4.05 x 10	14,330
	LP #2	11/195	210/190	4.05 x 10	13,550
	LP #3	20/228	210/223	4.05 x 10	13,720
	LP #4	67/300	210/295	4.05 x 10	18,770
	IP	296/416	1040/416	6.22 x 10	45,660
	H.P.	745/510	5,700/519	6.22 x 10	49,700
	DFT	6.22x10 lb/hr @ 353 F			
F-4	Main Condensate Pumps and Motors (2 required)	Vertical Centerline, 4250 gpm, 600 hp motor, 410 ft TDH			
F-5	Feedwater Booster Pumps and Motors (2 required)	7,300 gpm, 3850 hp, 1510 ft TDH			
F-6	Main Boiler Feed Pumps and Turbine Drivers (3 required)	4900 gpm, 12,600 hp, 8,300 ft TDH			
F-7	Main Circulating Pumps and Motors (3 required)	82,000 gpm, 2250 hp, 75 ft TDH			
F-8	Cooling Towers (20 Cells)	246,000 gpm			
F-9	Forced Draft Fans (2 required)	Operating	971,000 cfm @ 80°F, S.P. = 19 in wg		
		Test Block	1,165,000 cfm @ 105°F, S.P. - 24.7 in wg		
		Motor	6500 hp		
F-10	Primary Air Fans (2 requried)	Operating	161,750 cfm @ 95°F, S.P. inlet 19 in wg, S.P. outlet = 42 in wg		
		Test Block	194,000 cfm @ 121°F, S.P. inlet 19 in wg, S.P. outlet = 54.6 in wg		
		Motor	2250 hp		
F-11	Electrostatic Precipitators (4 required)	Each 54 ft high x 92 ft wide x 44 ft long, 1,262,000 lb, 1296 kVA, 99% particulate removal efficiency, 695,000 acfm @ 300°F.			

Table 17 (page 4 of 4)

Eqpt. No.	Service	Description	
F-12	Scrubber - Turbulent Contact Absorber (6 required)	Each 60 ft high x 40 ft wide x 18 ft long, 316L-S.S., neoprene lined, 3 stages, 450,000 acfm @ 312°F & 13.9 psia.	
F-13	Air Heater (6 required)	Each 4.5 ft high x 21.5 ft wide x 37.5 ft long.	
F-14	Induced Draft Fans (4 required)	Operating	660,000 cfm @ 300°F, Total S.P. = 23 in wg
		Test Block	800,000 cfm @ 325°F, Total S.P. = 30 in wg
		Motor	5,000 hp
F-15	Forced Draft Fans for Reheater Air (6 required)	Operating	545,000 cfm @ 80°F, Total S.P. = 3.5 in wg
		Test Block	654,000 cfm @ 105°F, Total S.P. = 4.55 in wg
		Motor	650 hp
F-16	Exhaust Stack	40 ft I.D., 500 ft high	

Table 18 (page 1 of 8)

BALANCE OF PLANT ESTIMATE DETAIL FOR CONVENTIONAL STEAM CYCLE-WET GAS SCRUBBER
250 F STACK

	Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
1.0 STEAM GENERATOR (3)		
1.1 Steam Generator Erection		
- Erect only (supply by others): includes heat transfer surface and pressure parts; buckstays, braces and hangers; fuel-burning equipment; accessories; soot and ash equipment; control systems; brickwork, refractory and insulation	544	
- Supply and erect: includes support steel and access steel for above; miscellaneous materials and labor operations	296	6,800
1.2 Steam Generator Auxiliaries		
- Erect only (supply by others): includes fans; air preheater; flues and ducts to precipitators; insulation for flues and ducts; pulverizers, feeders and hoppers	185	
- Supply and erect: includes F.D. Fans (2 @ $390,000 ea*); I.D. Fans (4 @ $220,000 ea*)	12	1,680
1.3 Electrostatic Precipitators		
- Erect only (supply by others): includes electrostatic precipitators	99	
- Supply and erect: includes support steel for precipitators	4	220
	1,140	8,700

*based on suppliers' verbal budgetary quotations

Table 18 (page 2 of 8)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
2.0	TURBINE GENERATOR (3)		
-	Install only (supply by others): includes 835 mWe steam turbine; generator; exciter; auxiliary equipment; integral steam and auxiliary piping; insulation; miscellaneous labor operations	120	100
3.0	PROCESS MECHANICAL EQUIPMENT		
3.1	Boiler Feedwater Pumps (3)		
	includes turbine-driven main feedwater pumps and drivers (3 @ $940,000 ea.*); feedwater booster pumps and motors (2 @ $125,000 ea.*)	10	3,220
3.2	Main Circ. Water Pumps (3)		
	includes main circ. water pumps and motors (3 @ $220,000 ea.*)	3	700
3.3	Other Pumps (3)		
	includes condensate pumps and motors (2 @ $85,000 ea.*); and other pumps and drivers not listed elsewhere	5	650
3.4	Main Condenser* (3)		
	includes shells; tubes; air ejectors	16	2,120
3.5	Heaters, Exchangers, Tanks and Vessels (3)		
	includes l.p. feedwater heaters (4): i.p. feedwater heater; h.p. feedwater heater; deaerating heater and storage tank; miscellaneous heaters and exchangers; tanks and vessels	9	3,060
3.6	Stack and Accessories (3)		
	includes concrete stack and liner*; lights and marker painting; hoists and platforms; stack foundation	113	1,570

*based on suppliers' verbal budgetary quotations

Table 18 (page 3 of 8)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.7	Turbine Hall Crane (1)		
	includes crane and accessories	3	410
3.8	Coal Handling (2)		
	includes railcar dumping equipment; dust collectors; primary and secondary crushing equipment; belt scale; sampling station; magnetic cleaners; mobile equipment; conveyors to pile; reclaiming feeders; conveyors to coal silos; coal silos	61	5,640
3.9	Limestone Handling (2)		
	includes magnetic cleaners; conveyor to limestone pile; reclaiming feeders; belt scale; conveyors to calciner	22	1,250
3.10	Ash Handling (2)		
	includes bottom ash system; fly ash handling system for precipitators and air preheater; ash conveyors; ash storage silos (2) with feeders, unloaders and foundations; railcar loading equipment	61	3,580
3.11	Cooling Towers* (3)		
	includes mechanical draft towers with fans and motors	52	2,230
3.12	Other Mechanical Equipment (3)		
	includes water treatment and chemical injection; air compressors and auxiliaries; fuel oil ignition and warm-up; screenwell, miscellaneous plant equipment; equipment insulation	30	1,660

*based on suppliers' verbal budgetary quotations

Table 18 (page 4 of 8)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.13	Scrubber Ductwork (3)	207	3,270
-	includes flue gas duct outboard of electrostatic precipitators; duct lining; duct insulation; dampers and expansion joints		
3.14	Scrubber Flue Gas Equipment (3)	27	3,090
-	includes F.D. fans for flue gas reheat (6 @ $200,000 ea.*); air heaters for flue gas reheat (6 @ $280,000 ea.*)		
3.15	Wet Lime SO_2 Scrubbers (3)	86	6,930
-	includes complete SO_2 scrubber vessels with presaturator and mist eliminator systems (6 @ $1,000,000 ea.*)		
3.16	Scrubber Lime System (3)	66	3,660
-	includes limestone calciner with travelling grate kiln ($2,700,000*); Kiln stack; coal conveyor, bucket elevator and storage bin for kiln; lime conveyor, bucket elevator and storage silos; lime slaker ($120,000*)		
3.17	Scrubber System Pumps (3)	10	1,080
-	includes slurry recycle (18 @ $40,000 ea.*); mist eliminator wash (3 @ $25,000 ea.*); slurry storage and transfer (4 @ $4,000 ea.*); slurry feed (3 @ $5,000 ea.*); pond feed tank (3 @ $10,000 ea.*); pood feed booster (2 @ $15,000 ea.*); pond water recycle and booster (4 @ $12,500 ea.*)		
3.18	Scrubber System Tanks (3)	4	2,180
-	includes tanks and agitators for absorber effluent hond, pond feed, entrainment separator surge, slurry surge, slurry storage, slurry transfer		
		785	46,300

*based on suppliers' verbal budgetary quotations

Table 18 (page 5 of 8)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
4.0	ELECTRICAL (5)		
4.1	Main Transformers*	4	2,020
4.2	Other Transformers* and Main Bus	17	1,280
-	includes startup transformer; station service transformers including those for scrubber system; generator main bus		
4.3	Switchgear and Control Centers	42	3,400
-	includes switchgear and load centers; motor control centers; local control stations; distribution panels, relay and meter boards		
4.4	Other Electrical Equipment	363	2,010
-	includes communications; grounding; cathodic and freeze protection; lighting; preoperational testing		
4.5	Auxiliary Diesel Generator	2	110
-	includes diesel generator, batteries and associated d.c. equipment		
4.6	Conduit, Cable Trays, Wire and Cable	632	4,080
		1,060	12,900

*based on suppliers' verbal budgetary quotation

Table 18 (page 6 of 8)

			Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
5.0	CIVIL AND STRUCTURAL			
	5.1	Concrete Substructures and Foundations (1)	340	2,800
	-	includes turbine and boiler building substructure; coal, limestone and ash handling foundations, pits and tunnels; miscellaneous equipment foundations; auxiliary buildings substructures; miscellaneous concrete		
	5.2	Superstructures (1)	275	7,960
	-	includes turbine building; auxiliary yard buildings; boiler enclosure		
	5.3	Earthword (1)	130	300
	-	includes building excavations; coal, limestone and ash handling excavations; circ. water system excavations; miscellaneous foundation excavations; dewatering and piling		
	5.4	Cooling Tower Basin and Circ. Water System (3)	90	1,380
	-	includes circ. water pump pads, riser and concrete envelope for pipe; cooling tower basin; circ. water pipe; cooling tower miscellaneous steel and fire protection		
	5.5	SO_2 Scrubber Civil and Structural (1)	180	3,660
	-	includes foundations, earthwork and structures particular to scrubber equipment		
			1,015	16,100

Table 18 (page 7 of 8)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
6.0	PROCESSING PIPING AND INSTRUMENTATION		
6.1	Steam and Feedwater Piping (3)	81	3,850
-	includes main steam; extraction steam; hot reheat; cold reheat; feedwater and condensate large piping, valves and fittings		
6.2	SO_2 Crubber System Large Piping (3)	53	2,630
-	includes maker-up water; resaturation slurry water; mist eliminator wash; absorber slurry effluent tank overflow; pond feed; pond recycle water; lime slurry piping; recycle slurry piping; air heater steam supply; air heater condensate return		
6.3	Other Large Piping (3)	231	4,050
-	includes all piping, valves and fittings of 2-inch diameter and less		
6.5	Hangers and Misc. Labor Operations (3)	420	1,460
-	includes all hangers and supports; material handling; scaffolding; misc. labor operations		
6.6	Pipe Insulation (3)	63	660
6.7	Instrumentation and Controls (5)	220	4,900
		1,220	18,900

Table 18 (page 8 of 8)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
7.0	YARDWORK AND MISCELLANEOUS (1)		
7.1	Site Preparation and Improvements	87	10
-	includes soil testing; clearing and grubbing; rough grading; finish grading; landscaping		
7.2	Site Utilities	5	50
-	includes storm and sanitary sewers; nonprocess service water		
7.3	Roads and Railroads	27	740
-	includes railroad spur; roads, walks and parking areas		
7.4	Yard Fire Protection, Fences and Gates	52	600
7.5	Water Treatment Ponds	88	20
-	includes earthwork; pond lining; offsite pipeline		
7.6	Lab, Machine Shop and Office Equipment	1	280
		260	1,700

The seven major categories used by the architect-engineer relate to the principal field labor skills to be applied. A modified subdivision of costs was made using the following categories:

1. Land improvements and structures
2. Coal handling
3. Prime cycle plant equipment
4. Bottoming cycle (not applicable to this plant)
5. Electrical plant and instrumentation

The appropriate subdivision number for each item or major category in Table 18 is indicated after its title in parentheses.

Plant Cost Estimate

The major components from Table 16 and the balance of plant costs appropriate to each of the categories of field labor skills used in Table 18 are combined in Table 19 to show a total of $301.62 million.

The home office and fee of 15 percent is applied only to the balance of plant costs. A contingency of 20 percent of all prior costs is applied to cover expected costs not specifically included in the original estimating process. The total capital cost of $403 million represents $492/kW based on total generation, or $540/kW on net station output.

A reallocation of costs according to equipment function is presented in Table 20. Items 1 through 6 include everything in the preceding table. Item 7 adds the value of escalation and interest during the 5.5 year construction time. This item is 55 percent of the prior total. The result is a final plant cost of $761/kW of total generation, or $835/kW of net station output.

Table 19

PLANT CAPITAL COST BREAKDOWN
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-250 F STACK

	COSTS (MILLIONS OF DOLLARS)				
CATEGORIES	COMPONENTS	DIRECT LABOR(1)	INDIRECT FIELD(2)	MATERIALS(3)	TOTAL
1.0 Steam Generators	45.88	13.40	12.06	8.70	80.04
2.0 Turbine Generator	26.00	1.41	1.27	0.10	28.78
3.0 Process Mechanical Equipment		9.22	8.30	46.30	63.82
4.0 Electrical		12.46	11.21	12.90	36.57
5.0 Civil and Structural		11.93	10.73	16.10	38.76
6.0 Process Piping and Instrumentation		14.34	12.90	18.90	46.14
7.0 Yardwork and Miscellaneous		3.06	2.75	1.70	7.51
	71.88	65.82	59.22	104.70	301.62
	BOP Labor, Materials & Indirects (Sum of 1 + 2 + 3)			229.74	
	A/E Home Office & Fee @ 15%				34.50
	Total Plant Cost				336.12
	Contingency @ 20%				67.22
	Total Capital Cost				403.34

Table 20

PLANT CAPITAL COST ESTIMATE SUMMARY (APPROXIMATE DISTRIBUTION)
CONVENTIONAL STEAM PLANT-WET SCRUBBERS-250 F STACK

		COSTS (MILLIONS OF DOLLARS)			
		MAJOR COMPONENTS	BOP MATERIALS	SITE LABOR (DIRECT & INDIRECT)	TOTAL
1.0	Land Improvements & Structures	0	13.2	22.5	35.7
2.0	Coal Handling	0	34.3	16.2	50.5
3.0	Prime Cycle Plant Equipment	71.9	44.3	62.7	178.9
4.0	Bottom Cycle Not Applicable				
5.0	Electrical Plant & Instrumentation	0	12.9	23.7	36.6
	Subtotal	71.9	104.7	125.0	301.6
6.0	A-E Service & Contingency				101.7
7.0	Escalation & Interest During Construction				221.0
			Total M$		624.3
			Plant Output MW		747.2
			Total $/kW		835.4

6. NATURAL RESOURCES AND ENVIRONMENTAL INTRUSIONS

The natural resources required for this plant are listed in Table 21. The sorbent use is low because of the highly efficient chemical system. The poor coal use reflects a reduced generation due to steam diversion for reheating and, in addition, added auxiliary power consumed in the wet gas scrubber system and in the induced draft fans. The water usage is mostly for the cooling tower and is at conventional levels.

The great land area consigned to sludge accumulation suggests that some innovative exploitation of the sludge might reduce this element of resource wastage. To a certain degree the sludge ponds may represent an ongoing threat to the surroundings. Their reclamation for agriculture or their use as a chemical resource could offset the liability of their accumulation.

The environmental intrusions are enumerated in Table 22. The sulfur emissions are three-quarters of the allowed 1.2 lb/MBtu. This results from 90 percent capture, whereas 83 percent capture would just equal the limit. The NO_x released would be held just under the current limit by the use of staged combustion in firing the boiler. The stack gas reheaters place a greater fraction of heat rejection at the stack as compared with other plans.

Sensitivity To Emission Targets

The chemical processes in use for wet scrubbing and for combustion do not lend themselves to drastic changes in current emission targets. If the sulfur emission target were to be half the current level (0.6 lb SO_2/MBtu rather than the current 1.2 lb SO_2/MBtu), the scrubbers would increase in size and gaseous pressure drop by a factor of 50 percent. The auxiliary power loss in the scrubber system would tend to increase by 5 MW. Reduction in particulate emissions would require an increase of electrostatic precipitators of 100 percent to reach 0.05 lb/MBtu or half the current standard.

The reduction of NO_x would be particularly difficult, since there is already a burden of fuel-bound nitrogen to which the thermal NO_x is added. Reduction to half the current standard is not currently deemed feasible.

Table 21

NATURAL RESOURCE REQUIREMENTS
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS 250 F STACK

	VALUE
Sorbent, Limestone lb/kWh	0.16
Coal, lb/kWh	0.996
Water, Total (Gal/kWh)	
Cooling	
Evaporation	0.56
Blowdown	0.18
Plant General Use	0.01
Sulfur Cleanup Use	0.07
Total Land, Acres/100 MW_e	
Main Plant	12.3
Disposal Land (30 years)	239.0

Table 22

ENVIRONMENTAL INTRUSION
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-250 F STACK

EMISSIONS	LB/MBtu INPUT	LB/kWh OUTPUT
SO_x	0.867	0.0093
NO_x	0.65	0.0070
HC		
Particulates	0.092	0.00099
THERMAL POLLUTION		
Heat, Rejected Cooling Towers, Btu/kWh		4188
Heat, Rejected Stack, Btu/kWh		3130
Heat, Rejected Total, Btu/kWh		7318

WASTES	LB/kWh	M LB/DAY
Water Discharge	1.59	28.4
Dry Fly Ash	0.07	1.30
Sludge	0.19	3.46

7. SUMMARY PERFORMANCE AND COST

Table 23 summarizes the performance and cost for a 747 MW steam plant using wet gas scrubbers with 250 F stack temperature. The low overall plant efficiency of 32 percent is due to steam diversion for stack gas reheating and parasitic auxiliary loads imposed by the wet gas scrubbing system. The coal rate of 1 lb/kWh was a typical plant value 45 years ago. The high plant costs are effected by the additional costs of the scrubber system and the reduction of net output already noted. The net result is a cost of electricity (COE) of 39.8 mills/kWh, or 4 cents/kWh at the power plant boundary.

The sensitivity of the cost of electricity to these factors is presented in Table 24.

Table 23

SUMMARY PERFORMANCE AND COST
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-250 F STACK

ITEM		
Net Power Plant Output (MW_e - 60 Hz - 500 kV)		747.2
Thermodynamic Efficiency (%)		40.7
Power Plant Efficiency (%)		31.8
Overall Energy Efficiency (%)		31.8
Coal Consumption (LB/kWh)		0.996
Total Wastes (LB/kWh)		0.27
Plant Capital Cost ($ Million)		624.3
Plant Capital Cost ($\$/kW_e$)		835.4
Cost of Electricity, Capacity Factor = 0.65		
Capital	(MILLS/kWh)	26.4
Fuel	(MILLS/kWh)	10.7
Maintenance & Operation	(MILLS/kWh)	2.6
Total	(MILLS/kWh)	39.8
Estimated Time of Construction (Years)		5.5
Approximate Date of First Commercial Service		1980 - 1982

Table 24

COST OF ELECTRICITY (COE) SENSITIVITY CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-250 F STACK

	BASE CAPACITY FACTOR 0.65	FUEL COST INCREASE 50%	LABOR COST INCREASE 20%	MATERIALS INCREASE 20%	CAPACITY FACTOR CHANGE 0.5 & 0.8	
COE, Capital	26.4	26.4	28.7	29.4	34.3	21.5
COE, Fuel	10.7	16.1	10.7	10.7	10.7	10.7
COE, O&M	2.6	2.6	2.6	2.6	2.7	2.6
TOTAL COE	39.8	45.2	42.0	42.8	47.8	34.8

8. ALTERNATIVE PLANT CONSIDERATIONS

Stack Gas Reheat To 175 F

An appraisal was made for the identical boiler and scrubber configuration wherein the stack gas was reheated to 175 F instead of 250 F. Table 25 indicates those elements that were unchanged, those elements that were significantly changed, and some details of the greatly reduced stack gas reheat effect. The requirement for stack gas reheat would be reduced by a factor of 2.5. The reheat energy release from air heated to 335 F would increase by a factor of 1.9. The combined effect reduces the heat duty on the steam reheaters to 23 percent of that required heretofore.

A revised steam-turbine cycle heat balance was made to reflect these changes. The major changes over values found on Figure 5 are tabulated in Table 26. The overall energy balance of Table 11 would be unchanged except for the generated power. The changes in Table 26 and the fixed values from Table 4 were used to reassess the auxiliary power losses as presented in Table 27.

The system output as shown in Table 28 becomes 795.5 MW, an increase of 6 percent over the previous case with 250 F stack.

The revisions to the wet scrubber system relate entirely to the reduced steam and air flows for the stack gas reheat. The lower table on Figure 7 shows these details for the 175 F stack configuration. Tables 6, 8, and 10 show the changes in the scrubber system cost details.

The overall plant arrangement details would not be changed. The increased generation does change the size of electrical apparatus, as shown on Figure 13.

The balance-of-plant equipment list is presented in Table 29. The balance-of-plant direct labor man-hours and material costs are presented in Table 30. These combine with the major equipment costs to determine a plant cost of $396 million as detailed in Table 31. Table 32 redistributes the costs and adds on the escalation and interest during construction. The result is a plant capital cost of $771 per kilowatt of net plant output.

Performance And Cost--175 F Stack

Table 33 summarizes the system performance and cost with 175 F stack reheat, and Table 34 compares the influence of 250 F and 175 F stack reheat cases. On every measure the 175 F stack shows advantage over the 250 F stack. The sensitivity of the cost of electricity to the several major variables is presented in Table 35.

Natural resource usage and environmental intrusions would be comparable to Table 21 and 22 values, but there would be a 6 percent reduction where the basis was kilowatt hours.

Table 25

CONVENTIONAL STEAM PLANT WET GAS SCRUBBERS-175 F STACK FOR 175 F STACK IN PLACE OF 250 F STACK

NOT CHANGED

- Coal Rate, Air Rate, Gas Rate
- Scrubber Configuration
- Heat to Steam Cycle

CHANGED

- Heat to Reheat Stack Gas
- Reheat Air Flow
- Steam to Stack Gas Reheaters
- Steam Turbine Cycle
- Generated Power
- Heat to Cooling Towers

REHEAT EFFECTS	250 F	175 F	RATIO
Stack Gas Reheat from 125 F	125 F	50 F	2.5
Air Heat Release from 335 F	85 F	160 F	1/1.9
Air and Steam Flow Ratios	1	0.23	4.3

Table 26

STEAM TURBINE CYCLE CHANGES FOR 175 F STACK VERSUS 250 F STACK

Parameter	250 F Stack	175 F Stack
Turbine Type	TC4F33.5	TC4F33.5
Heat to steam, cycle, MBtu/Hr	6867.4	6867.4
Generator output, kW	819938	868620
Gross heat rate, Btu/kWh	8375.54	7906.13
Steam-to-gas reheater, lb/Hr	926,000	213,426
Last stage flow, lb/Hr	2,888,123	3,472,980
Condensate pump flow, lb/Hr	3,925,037	4,668,000
Heat to condenser, MBtu/Hr	3086	3638
Turbine cost, M$	26.0	26.75

Table 27

AUXILIARY LOSS BREAKDOWN
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-175 F STACK

ITEM	ASSUMPTIONS	NO. OF UNITS	TOTAL MW_e
Furnace			
FD Fans	19" Δ P, 0.82 EFF	4	7.3
PA Fans	42" Δ P, 0.82 EFF	4	2.9
ID Fans	23" Δ P, 0.78 EFF	4	8.8
ESP	695,000 CFM, 300 F, 0.986 EFF	4	5.2
Pulverizers		8	7.6
			31.8
Turbine Auxiliary	0.33% of Gross kW	1	2.9
Wet Scrubber			8.6
Major Pumps			
Booster	600 PSI, 6 Million #, 75% x 90%	2	3.7
Condensate	185 PSI, 4.7 Million #, 70% x 90%	2	1.2
Circ. Water	Proportion to Cooling Heat Duty	3	5.6
			10.5
Water Intake	A/E Estimate	2	0.9
Solids Handling	Based on Rates and Lifts	1	3.0
"Hotel" Loads	A/E Estimate 1% of Generation	1	8.4
Cooling Tower Fans	Proportional to Heat Duty	20	2.7
Transformers	0.5% of Gross Generation	4	4.3
		TOTAL AUXILIARY POWER =	73.1

Table 28

SYSTEM OUTPUT
CONVENTIONAL STEAM PLANT-WET SCRUBBERS-175 F STACK

Steam Cycle Output	868.6 MW
Total Auxiliary Losses	73.1 MW
Net Powerplant Output (60 Hz AC-500kV)	795.5 MW

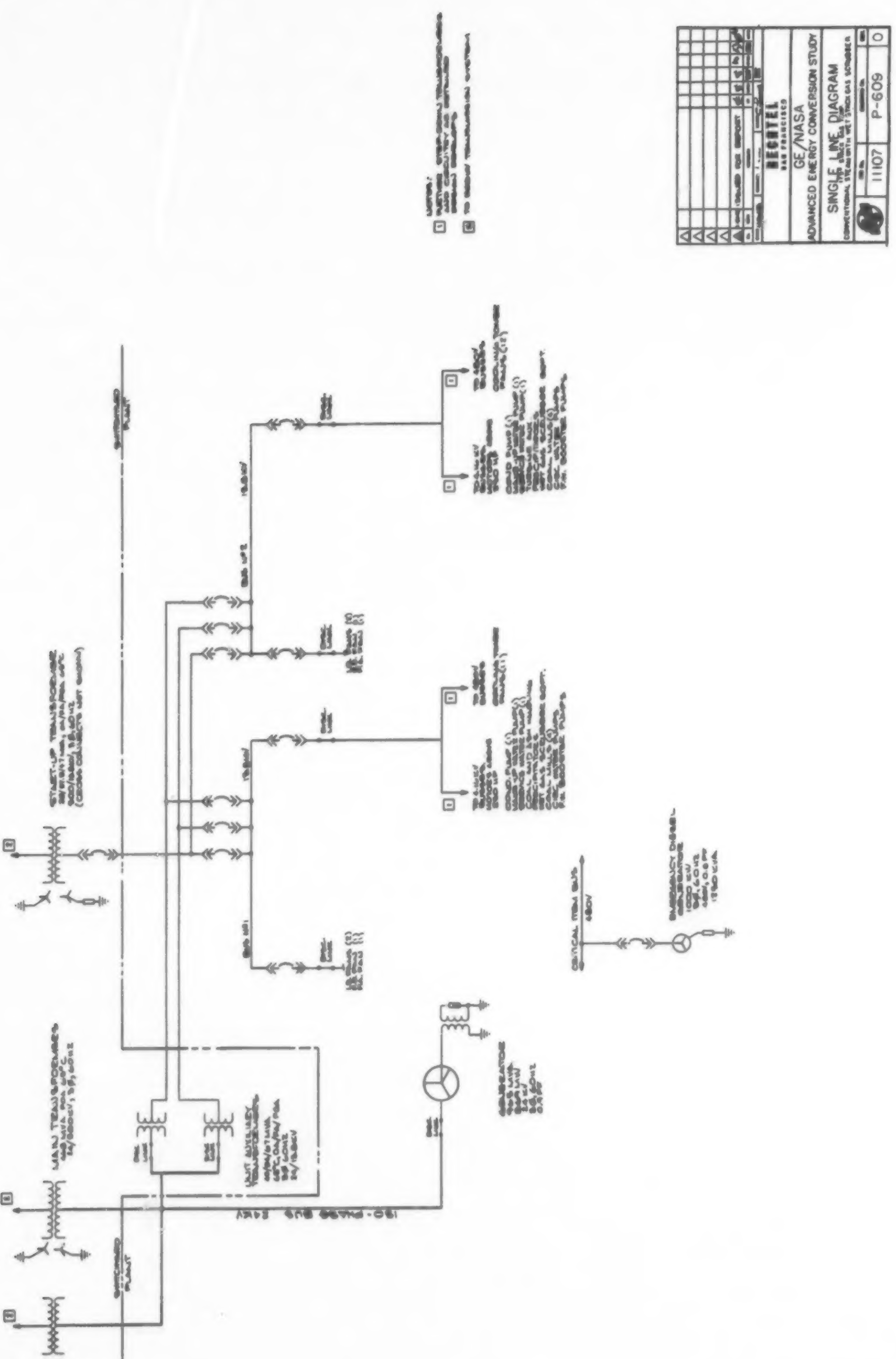
MAIN TRANSFORMER
UNIT AUXILIARY TRANSFORMERS
START-UP TRANSFORMER
GENERATOR
CRITICAL ITEM BUS 480V
EMERGENCY DIESEL GENERATOR
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
SINGLE LINE DIAGRAM
11107
P-609
0

Figure 13. Conventional Steam Plant with Wet Gas Scrubber—175 F

TABLE 29 (page 1 of 4)

EQUIPMENT LIST FOR CONVENTIONAL STEAM CYCLE--
WET SCRUBBERS, 175 F STACK

EQPT. NO.	SERVICE	DESCRIPTION
	1. Coal, and Limestone Handling Systems	
C-1	Coal Conveyor Belt	60 in wide, 340 ft long, 3000 tph
C-2	" " "	60 in " 760 ft " 3000 "
C-3	" " "	60 in " 190 ft " 3000 "
C-4	" " "	42 in " 980 ft " 500 "
C-5	" " "	42 in " 540 ft " 500 "
C-6	" " "	42 in " 170 ft " 500 "
C-7	" " "	42 in " 110 ft " 500 "
C-8	" " " (2)	30 in " 160 ft " 300 "
C-9	Limestone Conveyor Belt	60 in " 500 ft " 3000 "
C-10	" " "	24 in " 630 ft " 65 "
C-11	" " "	24 in " 420 ft " 65 "
C-12	Limestone Bucket Conveyor	24 in " 120 ft " 100 "
C-13	Traveling Grate Kiln System (Package)	650 ton/day nominal lime production (880 ton; day design capacity), 12 ft wide x 48 ft long traveling grate, 13 ft I.D. x 180 ft long rotary kiln with Niems type cooler. Include coal grinding/firing equipment, control panel/instrumentation, all refractories and drives, induced draft fan, baghouse dust collector and ducting.
C-14	Coal Conveyor Belt	18 in wide 60 ft long 20 tph
C-15	Lime Bucket Conveyor (2)	24 in " 140 ft " 40 "
C-16	Fly Ash Silos (2)	Total volume 833, 184 ft^3, 80 ft dia x 85 ft high

TABLE 29 (page 2 of 4)

2. Electrical Systems

EQPT. NO.	SERVICE	DESCRIPTION
E-1,2	Main Transformers (2)	468 MVA FOA 65°C, 24/500 kV
E-3,4	Unit Aux. Transformers (2)	40/54/67 MVA 65°C, OA/FA/FOA,24/13.8 kV, 3Ø, 60 Hz
E-5	Emergency Diesel Gen.	1000 kW, 3Ø, 60 Hz, 480 V, 0.8 PF
E-6	Start-up Transformer	28/37.5/47 MVA, OA/FA/FOA, 500/13.8 kV FOA 65°C, 3Ø, 60 Hz
E-7 thru 20	Miscellaneous 480 V LCC Transformers (14)	1689 kVA, OA, 65°C, 13.8 kV/480V/277V, 3Ø, 60 HZ
E-21 & 22	BLR. Aux. Transformers (2)	5500 kVA, OA, 65°C, 13.8/4.16 kV, 3Ø, 60 Hz
E-23 & 24	LCC Transformers (2)	7000 kVA, OA, 65°C, 13.8/4.16 kV, 3Ø, 60 Hz
E-25 & 26	Scrubber Transformers (2)	5000 kVA, OA, 65°C, 13.8/4.16 kV, 3Ø, 60 Hz

3. Main Fluid Systems

EQPT. NO.	SERVICE	DESCRIPTION
F-1	Main Condenser	3.97×10^5 ft^2 of Heat Transfer Area
F-2	Piping	
	Circ. Water	I.D. = 123 in
	Main Steam	I.D. = 15.3 in, tm = 3.97 in
	B.F.W.	I.D. = 26.52 in, tm = 0.675 in
	Cold R.H.	I.D. = 32.54 in, tm = 1.57 in
	Hot R.H.	I.D. = 18.1 in, tm = 2.25 in

TABLE 29 (page 3 of 4)

EQPT. NO.	SERVICE	DESCRIPTION			
F-3	Feedwater Heaters	Shell Press/Temp psia/°F	Tube Press/Temp psia/°F	Flow (100%) lb/hr	Heat Transfer Area ft^2
	LP #1	5/163	210/158	4.75×10^6	17,170
	LP #2	11/195	210/190	4.75×10^6	16,260
	LP #3	20/228	210/223	4.75×10^6	16,600
	LP #4	67/300	210/295	4.75×10^6	22,710
	IP	296/416	1040/416	6.22×10^6	45,660
	H.P.	745/510	5700/519	6.22×10^6	49,700
	DFT	6.22×10^6 lb/hr, @ 353°F			
F-4	Main Cond. Pumps and Motors (2)	Vert. Cent. 5100 gpm, 750 hp motor, 410 ft TDH			
F-5	F.W. Booster Pumps & Motors (2)	7,300 gpm, 3850 hp, 1510 ft TDH			
F-6	Main Boiler Feed Pumps & Turbine Drivers (3)	4900 gpm, 12,600 hp, 8,300 ft TDH			
F-7	Main Circ. Pumps and Motors (3)	95,000 gpm 2500 hp, 75 ft TDH			
F-8	Cooling Towers (23 Cells)	242,058 gpm			
F-9	F.D. Fans (2)	Operating	971,000 cfm @ 80°F, S.P. = 19 in wg		
		Test Block	1,165,000 cfm @ 105°F, S.P. = 24.7 in wg		
		Motor	6,500 hp		
F-10	P.A. Fans (2)	Operating	161,750 cfm @ 96°F, S.P. inlet in wg S.P. outlet = 42 in wg		
		Test Block	194,000 cfm @ 121°F, S.P. inlet 19 in wg S.P. outlet = 54.6 in wg		
		Motor	2250 hp		

TABLE 29 (page 4 of 4)

EQPT. NO.	SERVICE	DESCRIPTION	
F-11	Electrostatic Precipitators (4)	Each 54 ft high x 92 ft wide x 44 ft long, 1,262,000 lb, 1296 kVA, 99% particulate removal efficiency, 695,000 acfm @ 300°F	
F-12	Scrubber - Turbulent Contact Absorber (6)	Each 60 ft high x 40 ft wide x 18 ft long, 316L-S.S., neoprene lined, 3 stages, 450,000 acfm @ 312°F & 13.9 psia	
F-13	Air Heaters (6)	Each 2.5 ft high x 18.2 ft wide x 10.7 ft long	
F-14	I.D. Fans (4)	Operating	600,000 cfm @ 300°F, Total S.P. = 23 in wg
		Test Block	800,000 cfm @ 325°F, Total S.P. = 30 in wg
		Motor	5,000 hp
F-15	F.D. Fans for Reheater Air (6)	Operating	123,000 cfm @ 80°F, Total S.P. = 3.5 in wg
		Test Block	147,000 cfm @ 105°F, Total S.P. = 4.55 in wg
		Motor	150 hp
F-16	Exhaust Stack (1)	27 ft I.D., 500 ft high	

TABLE 30 (page 1 of 9)

BALANCE OF PLANT ESTIMATE DETAIL CONVENTIONAL STEAM CYCLE-- WET LIME STACK GAS SCRUBBER, 175 F STACK GAS

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
1.0	STEAM GENERATOR		
1.1	Steam Generator Erection (3)		
-	Erect only (supply by others): includes heat transfer surface and pressure parts; buckstays, braces and hangers; fuel burning equipment; accessories; soot and ash equipment; control systems; brickwork; refractory and insulation	544	
-	Supply and erect: includes support steel and access steel for above; miscellaneous materials and labor operations	296	6,800
1.2	Steam Generator Auxiliaries (3)		
-	Erect only (supply by others): includes P.A. fans; air preheater; flues and ducts to precipitators; insulation for flues and ducts; pulverizers, feeders and hoppers	185	
-	Supply and erect: includes F.D. Fans (2 @ $390,000 ea*); I.D. fans (4 @$220,000 ea.*)	12	1,680
1.3	Electrostatic Precipitators (3)		
-	Erect only (supply by others): includes electrostatic precipitators	99	
-	Supply and erect: includes support steel for precipitators	4	220
		1,140	8,700

*based on supplier's verbal budgetary quotations

TABLE 30 (page 2 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
2.0	TURBINE GENERATORS (3)		
-	Install only (supply by others): includes 835 MWe steam turbine; generator; exciter; auxiliary equipment; integral steam and auxiliary piping; insulation; miscellaneous labor operations	120	100
3.0	PROCESS MECHANICAL EQUIPMENT		
3.1	Boiler Feedwater Pumps (3)		
-	includes turbine-driven main feedwater pumps and drivers (3 @ $940,000 ea.*); feedwater booster pumps and motors (2 @ $125,000 ea.*)	10	3,220
3.2	Main Circ. Water Pumps (3)		
-	includes main circ. water pumps and motors (3 @ $235,000 ea.*)	3	750
3.3	Other Pumps (3)		
-	includes condensate pumps and motors (2 @ $95,000 ea.*); and other pumps and drivers not listed elsewhere	5	670
3.4	Main Condenser* (3)		
-	includes shells; tubes; air ejectors	17	2,440
3.5	Heaters, Exchangers, Tanks and Vessels (3)		
-	includes l.p. feedwater heaters (4): i.p. feed water heater; h.p. feedwater heater; deaerating heater and storage tank; miscellaneous heaters and exchangers; tanks and vessels	9	3,160

*based on suppliers' verbal budgetary quotations

TABLE 30 (page 3 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.6	Stack and Accessories (3)		
-	includes concrete stack and liner*; lights and marker painting; hoists and platforms; stack foundation	86	1,240
3.7	Turbine Hall Crane (1)		
-	includes crane and accessories	3	410
3.8	Coal Handling (2)		
-	includes railcar dumping equipment; dust collectors; primary and secondary crushing equipment; belt scale; sampling station; magnetic cleaners; mobile equipment; conveyors to pile; reclaiming feeders; conveyors to coal silos; coal silos	61	5,640
3.9	Limestone Handling (2)		
-	includes magnetic cleaners; conveyor to limestone pile; reclaiming feeders; belt scale; conveyors to calciner	22	1,250
3.10	Ash Handling (2)		
-	includes bottom ash system; fly ash handling system for precipitators and air preheater; ash conveyors; ash storage silos (2) with feeders, unloaders and foundations; railcar loading equipment	61	3,580

*based on suppliers' verbal budgetary quotations

TABLE 30 (page 4 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.11	Cooling Towers* (3)		
-	includes mechanical draft towers with fans and motors	60	2,580
3.12	Other Mechanical Equipment (3)		
-	includes water treatment and chemical injection; air compressors and auxiliaries; fuel oil ignition and warm-up; screenwell; miscellaneous plant equipment; equipment insulation	30	1,660
3.13	Scrubber Ductwork (3)	120	1,950
-	includes flue gas duct outboard of electrostatic precipitators; duct lining; duct insulation; dampers and expansion joints		
3.14	Scrubber Flue Gas Equipment (3)	7	900
-	includes F.D. fans for flue gas reheat (6 @ $85,000 ea.*); air heaters for flue gas reheat (6 @ $50,000 ea.*)		
3.15	Wet Lime SO_2 Scrubbers (3)	86	6,930
-	includes complete SO_2 scrubber vessels with presaturator and mist eliminator systems (6 @ $1,000,000 ea.*)		

*based on suppliers' verbal budgetary quotations

TABLE 30 (page 5 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.16	Scrubber Lime System (3)	66	3,660
-	includes limestone calciner with travelling grate kiln ($2,700,000*); Kiln stack; coal conveyor, bucket elevator and storage bin for filn; lime conveyor, bucket elevator and storage silos; lime slaker ($120,000*)		
3.17	Scrubber System Pumps (3)	10	1,080
-	includes slurry recycle (18 @ $40,000 ea.*); mist eliminator wash (3 @ $25,000 ea.*); slurry storage and transfer (4 @ $4,000 ea.*); slurry feed (3 @ $5,000 ea.*); pond feed tank (3 @ $10,000 ea.*); pond feed booster (2 @ $15,000 ea.*); pond water recycle and booster (4 @ $12,500 ea.*)		
3.18	Scrubber System Tanks (3)	4	2,180
-	includes tanks and agitators for absorber effluent hold, pond feed, entrainment separator surge, slurry surge, slurry storage, slurry transfer		
		660	43,300

*based on suppliers' verbal budgetary quotations

TABLE 30 (page 6 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
4.0	ELECTRICAL (5)		
4.1	Main Transformers*	4	2,020
4.2	Other Transformers* and Main Bus	17	1,280
-	includes startup transformer; station service transformers including those for scrubber system; generator main bus		
4.3	Switchgear and Control Centers	42	3,400
-	includes switchgear and load centers; motor control centers; local control stations; distribution panels, relay and meter boards		
4.4	Other Electrical Equipment	363	2,010
-	includes communications; grounding; cathodic and freeze protection; lighting; pre-operational testing		
4.5	Auxiliary Diesel Generator	2	110
-	includes diesel generator, batteries and associated d.c. equipment		
4.6	Conduit, Cable Trays, Wire and Cable	632	4,080
		1,060	12,900

*based on suppliers' verbal budgetary quotations

TABLE 30 (page 7 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
5.0	CIVIL AND STRUCTURAL		
5.1	Concrete Substructures and Foundations (1)	340	2,800
-	includes turbine and boiler building substructures; coal, limestone and ash handling foundations, pits and tunnels; miscellaneous equipment foundations; auxiliary buildings substructures; miscellaneous concrete		
5.2	Superstructures (1)	275	7,960
-	includes turbine building; auxiliary yard buildings; boiler enclosure		
5.3	Earthwork (1)	130	300
-	includes building excavations; coal, limestone and ash handling excavations; circ. water system excavations; miscellaneous foundation excavations; dewatering and piling		
5.4	Cooling Tower Basin and Circ. Water System (3)	105	1,680
-	includes circ. water pump pads, riser and concrete envelope for pipe; cooling tower basin; circ. water pipe; cooling tower miscellaneous steel and fire protection		

TABLE 30 (page 8 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
5.5	SO_2 Scrubber Civil and Structural (1)	180	3,660
-	includes foundations, earthwork and structures particular to scrubber equipment		
		1,030	16,400
6.0	PROCESS PIPING AND INSTRUMENTATION		
6.1	Steam and Feedwater Piping (3)	81	3,850
-	includes main steam; extraction steam; hot reheat; cold reheat; feedwater and condensate large piping, valves and fittings		
6.2	SO_2 Scrubber System Large Piping (3)	51	2,370
-	includes make-up water; resaturation slurry water; mist eliminator wash; absorber slurry effluent tank overflow; pond feed; pond recycle water; lime slurry piping; recycle slurry piping; air heater steam supply; air heater condensate return		
6.3	Other Large Piping (3)	231	4,050
-	includes auxiliary steam; process water; auxiliary systems		
6.4	Small Piping (3)	152	1,350
-	includes all piping, valves and fittings of 2-inch diameter and less		

TABLE 30 (page 9 of 9)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
6.5	Hangers and Misc. Labor Operations (3)	419	1,420
-	includes all hangers and supports; material handling; scaffolding; misc. labor operations		
6.6	Pipe Insulation (3)	62	640
6.7	Instrumentation and Controls (5)	219	4,820
		1,215	18,500
7.0	YARDWORK AND MISCELLANEOUS (1)		
7.1	Site Preparation and Improvements	87	10
-	includes soil testing; clearing and grubbing; rough grading; finish grading; landscaping		
7.2	Site Utilities	5	50
-	includes storm and sanitary sewers; nonprocess service water		
7.3	Roads and Railroads	27	740
-	includes railroad spur; roads, walks and parking areas		
7.4	Yard Fire Protection, Fences and Gates	52	600
7.5	Water Treatment Ponds	88	20
-	includes earthwork; pond lining; offsite pipeline		
7.6	Lab, Machine Shop and Office Equipment	1	280
		260	1,700

TABLE 31

BALANCE OF PLANT CAPITAL COST BREAKDOWN
CONVENTIONAL STEAM PLANT--WET GAS SCRUBBERS--175 F STACK

		Costs (Millions Of Dollars)				
Categories		Components	Direct Labor(1)	Indirect Field(2)	Materials(3)	Total
1.0	Steam Generators	45.88	13.40	12.06	8.70	80.04
2.0	Turbine Generator	26.75	1.41	1.27	0.10	29.53
3.0	Process Mechanical Equipment		7.76	6.98	43.30	58.04
4.0	Electrical		12.46	11.21	12.90	36.57
5.0	Civil and Structural		12.10	10.89	16.10	39.39
6.0	Process Piping and Instrumentation		14.27	12.85	18.50	45.62
7.0	Yardwork and Miscellaneous		3.06	2.75	1.70	7.51
		72.63	64.46	58.01	101.30	296.40
		BOP Labor, Materials & Indirects (Sum of 1 + 2 + 3)			223.2	
		A/E Home Office & Fee @ 15%				33.57
		Total Plant Cost				329.97
		Contingency @ 20%				65.99
		Total Capital Cost				395.96

Table 32

SUMMARY PERFORMANCE AND COST
CONVENTIONAL STEAM PLANT--WET GAS SCRUBBERS--175 F STACK

ITEM		
Net Power Plant Output (MW_e-60Hz-500kV)		795.5
Thermodynamic Efficiency (%)		43.1
Power Plant Efficiency (%)		33.8
Overall Energy Efficiency (%)		33.8
Coal Consumption (lb/kWh)		0.936
Total Wastes (lb/kWh)		0.25
Plant Capital Cost ($ Million)		613.6
Plant Capital Cost ($/$kW_e$)		771.3
Cost of Electricity, Capacity Factor = 0.65		
Capital	(Mills/kWh)	24.4
Fuel	(Mills/kWh)	10.1
Maintenance and Operation	(Mills/kWh)	2.5
Total	(Mills/kWh)	37.0
Estimated Time of Construction (Years)		5.5
Approximate Date of First Commercial Service		1980-1982

Table 33

SUMMARY PERFORMANCE AND COST
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-175 F STACK

ITEM		
Net Power Plant Output (MW_e - 60 Hz - 500 kV)		795.5
Thermodynamic Efficiency (%)		43.1
Power Plant Efficiency (%)		33.8
Overall Energy Efficiency (%)		33.8
Coal Consumption (LB/kWh)		0.936
Total Wastes (LB/kWh)		0.25
Plant Capital Cost ($ Million)		613.6
Plant Capital Cost ($/$kW_e$)		771.3
Cost of Electricity, Capacity Factor = 0.65		
Capital	(MILLS/kWh)	24.4
Fuel	(MILLS/kWh)	10.1
Maintenance & Operation	(MILLS/kWh)	2.5
Total	(MILLS/kWh)	37.0
Estimated Time of Construction (Years)		5.5
Approximate Date of First Commercial Service		1980 - 1982

Table 34

CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS
INFLUENCE OF STACK REHEAT TEMPERATURE

PARAMETER	250 F STACK	175 F STACK
Steam to Gas Reheater, LB/HR	926,000	213,426
Generator Output, kW	819,938	868,620
Net Plant Output, kW	747,200	795,500
Overall Energy Efficiency, %	31.8	33.8
Capital Cost, M$	624	614
Capital Cost, $/kW	835	771
Electricity Cost, Mills/kWh		
Capital	26.4	24.4
Fuel	10.7	10.1
O&M	2.6	2.5
TOTAL	39.8	37.0

Table 35

COST OF ELECTRICITY (COE) SENSITIVITY
CONVENTIONAL STEAM PLANT-WET GAS SCRUBBERS-175 F STACK

	BASE CAPACITY FACTOR 0.65	FUEL COST INCREASE 50%	LABOR COST INCREASE 20%	MATERIALS INCREASE 20%	CAPACITY FACTOR CHANGE 0.5 & 0.8	
COE, Capital	24.4	24.4	26.5	27.2	31.7	19.8
COE, Fuel	10.1	15.1	10.1	10.1	10.1	10.1
COE, O&M	2.5	2.5	2.5	2.5	2.6	2.5
TOTAL COE	37.0	42.1	39.1	39.8	44.4	32.4

No Scrubber, 250 F Stack Alternative

It is instructive to apply the methodology of these evaluations to a plant in which low-sulfur coal would be burned and the wet gas scrubbing system dispensed with. An identical boiler would be used. An air preheater enlarged 62 percent would bring the stack gas to 250 F as appropriate for low-sulfur fuel. The coal, air, and gas rates and boiler auxiliary losses would be scaled downward 1.4 percent by the boiler efficiency improvement. The electrostatic precipitator would precede the air preheater, to operate on the high-temperature low-sulfur gas stream. The heat to the steam cycle would be unchanged.

The steam turbine cycle would be identical with that of another system that has been analyzed in detail as to balance-of-plant man-hour and material costs. Use of the available data with the boiler and other data used with the wet scrubber cases permitted the synthesis of a cost breakdown and performance on a comparable basis.

Table 36 presents the breakdown of auxiliary losses, and Table 37 compares the performance and costs to the wet scrubber case with 175 F stack. The overall efficiency would be 36.2 percent. The cost of electricity would be 30.5 mills/kWh if the fuel cost remained at $1/MBtu. The price of low-sulfur coal at exact parity with the wet scrubber case (with 175 F reheat) would be $1.68/MBtu. A dominant plant difference would be the absence of the large sludge ponds. The reduced operating and maintenance cost reflects elimination of the costs of limestone, maintenance of the wet scrubber system, and operators for the wet scrubber system.

Table 36

AUXILIARY LOSS BREAKDOWN
CONVENTIONAL STEAM PLANT-NO SCRUBBERS-250 F STACK

ITEM	MW	SUBTOTAL MW
Furnace	—	26.55
FD Fans	3.35	
PA Fans	2.81	
ID Fans	7.84	
ESP	5.10	
Pulverizers	7.45	
Turbine Auxiliary	2.90	
Wet Scrubbers-None	0.00	
Major Pumps		11.07
Booster	3.37	
Circulating	4.70	
Other	3.00	
Solids Handling	3.00	
Hotel Loads	8.50	
Cooling Tower Fans	2.80	
Transformer Loss	4.40	
TOTAL AUXILIARY POWER =	59.22 MW	

Table 37

SYSTEM OUTPUT
CONVENTIONAL SYSTEM PLANTS

PARAMETER	175 F WET SCRUBBERS	250 F NO SCRUBBERS
Generator Output, MW	868.6	883.9
Auxiliary Losses, MW	73.1	59.2
Net Plant Output, MW	795.5	824.7
Output Ratio	1	1.04
Overall Energy EFF, %	33.8	36.2
Capital Cost, M$	614	511
Capital Cost, $/kW	771	620
Electricity Cost (COE), Mills/kWh		
Capital	24.4	19.6
Fuel	10.1	9.5*
O&M	2.5	1.4
TOTAL	37.0	30.5*

*Assumes fuel cost same as for 3.9% sulfur coal ($1.00/MBtu). Low sulfur coal at $1.68/MBtu would increase fuel cost such that the total COE for the no-scrubber case would equal the total COE for the scrubber case with 175 F reheat.

C. ATMOSPHERIC FLUIDIZED BED POWER PLANT

1. INTRODUCTION

The advanced steam cycle power plant with atmospheric fluidized beds (AFB) achieves the functions of combustion, steam generation, and sulfur capture in the four modular AFBs that replace a conventional steam boiler requiring wet flue gas scrubbers to remove sulfur. A simplified cycle schematic is presented in Figure 14 showing the major pieces of equipment.

The AFB combustor consists of four separate modules. Each module contains seven beds stacked one on top of another as described later. Six of the beds in each module will be primary combustion beds that burn coal. The bottom bed in each module is a carbon burnup cell, fed with carbon-containing fly ash and bed material from the primary beds in that module.

The system parameters are presented in Table 38. The Illinois No. 6 coal contains 3.9 percent sulfur. Eighty-three percent of the sulfur must be captured to meet the environmental emission limit of 1.2 lb/MBtu of fuel heat release. The capture medium is limestone fed into each of the six primary fluidized beds at twice the rate that would ideally capture all of the sulfur.* The 1550 F main bed operating temperature was selected to maximize sulfur capture at 85 percent of that present in the coal. Unburned carbon is conveyed from the main beds in the fly ash of the gas stream, and in the solids tapped from each bed. The 95 percent of the fly ash recovered in cyclone separators and the tapped primary bed solids is recycled to a carbon burnup cell, where a higher temperature of 2000 F and increased excess air of 30 percent produce a substantial burnup of residual combustibles. In essence, the main beds release energy while capturing sulfur as calcium sulfate. The carbon burnup cell releases additional energy but without the burden of sulfur capture; the result is a high boiler efficiency.

The steam cycle uses conventional conditions for a supercritical reheat steam turbine with seven feedwater heaters. The condenser back pressure was chosen to optimize the total cost of electricity.

The heat rejection system used 24 cells of mechanical draft evaporative cooling towers. The net power from the plant would be 814 MW representing 35.8 percent of the higher heating value (HHV) of the coal supplied to the plant.

---

*i.e. a Ca/S ratio of 2:1. This parameter was selected to be consistent with the PFB design. More recent data suggests that a Ca/S ratio of 2.5:1 to 3.5:1 may be required for adequate sulfur capture in AFB plants, resulting in increased costs.

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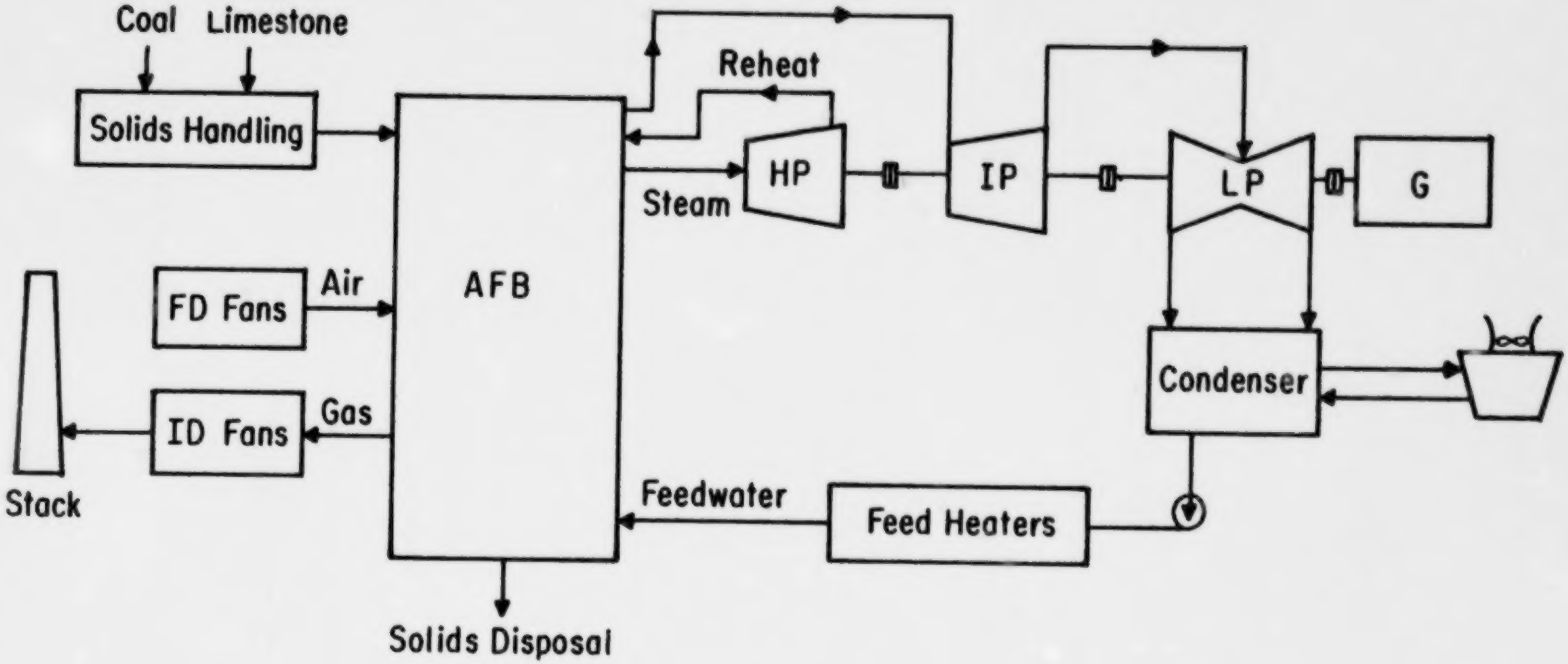

Coal
Limestone
Solids Handling
FD Fans
Air
ID Fans
Gas
Stack
AFB
Solids Disposal
Reheat
Steam
HP
IP
LP
G
Condenser
Feedwater
Feed Heaters

Figure 14. Simplified Schematic Diagram of Advanced Steam Cycle — Atmospheric Fluidized Bed.

Table 38

SYSTEM PARAMETERS
ADVANCED STEAM - ATMOSPHERIC FLUIDIZED BED

PARAMETER	VALUE OR DESCRIPTION
FUEL	
ILLINOIS NO. 6	10788 Btu/lb HIGHER HEATING VALUE $1/MBtu 3.9% SULFUR
LIMESTONE	SULFUR CAPTURE MEDIUM 0.257 lb/lb COAL
FURNACE	
ATMOSPHERIC FLUIDIZED BED COMBUSTOR AND STEAM GENERATOR (4 MODULES)	
MAIN BEDS (6 PER MODULE)	1550 F, COAL AND LIMESTONE
CARBON BURN-UP CELL (1 PER MODULE)	2000 F, FLY ASH AND SOLIDS DRAIN
EXCESS AIR	20%
PRIME CYCLE - STEAM PLANT	
WORKING FLUID	STEAM
TURBINE INLET	33500 PSI, 1000 F
REHEAT	644 PSI, 1000 F
CONDENSER	2'3" Hga, 106 F
FINAL FEEDWATER	4378 PSI, 505 F
HEAT REJECTION	
WET MECHANICAL DRAFT COOLING TOWERS	24 CELLS
STACK GAS TEMPERATURE	250 F

2. CYCLE DESCRIPTION

A detailed plant schematic is presented in Figure 15. State points and stream flows are shown in which the enthalpy values are referenced to 32 F water for steam and water and to an 80 F zero reference for air, combustion gases, and solids. The advanced feature of this power system is the use of AFB combustion to generate steam from high sulfur coal for a conventional steam turbine cycle with a single reheat of the steam.

Steam Turbine-Generator Cycle

The steam turbine is contained in four shells connected in tandem with a single generator. The low-pressure stages have four parallel flows exhausting downward into a common condenser. The condenser coolant is water recirculated in a closed circuit to the evaporative cooling towers. The regenerative feedwater heating cycle has four low-pressure feedwater heaters, a deaereating feedwater heater, and two high-pressure feedwater heaters. Part of the steam exhausted from the high-pressure turbine is used in feedwater heating, while the rest is returned to the AFB units to be reheated to 1000 F. Part of the steam from the reheat turbine exhaust is used for driving the boiler feed pump. The exhausts from those drive turbines are routed to the main condenser. All other pump drives are driven by electric motors and appear in the detailed account of auxiliary losses. The boiler feed pump and its drive are an integral part of the steam cycle and are fully accounted for in the heat balance for the steam turbine-generator.

The final feedwater temperature is 505 F for operation at the 100 percent point. It is conventional practice to reference the steam and feedwater states when a 5 percent greater steam flow exists at the valves wide open (VWO) operating point. For that case the feedwater would be at 510 F.

Atmospheric Fluidized Beds

The feedwater from the steam cycle passes first through the waterwalls that surround the AFB cells and then in sequence through economizers located in the gas flow above each fluidized bed. The hot carbon burnup cell is last in this sequence since, at 2000 F, it is the hottest combustor. Next, the fluid, which is now steam, is routed through primary superheaters in the gas space of the upper three main beds and then through finishing superheaters submerged in the upper three main beds. Steam at 3500 psig and 1000 F is discharged to the turbine. Steam returned for reheat at 716 psig follows a comparable routing through the lower three main beds. There will be four identical AFB modules operating in parallel to supply the steam required to the single steam turbine.

Each AFB module has six main beds rather than the two shown schematically in the figure. The injection of coal and limestone is assisted by the flow of primary air (PA) along with these solids. The main airflow (A) enters the bed in an upward flow through a perforated distribution plate that is the bottom of each fluidized bed. Most of the fluidized bed solids are the residual products of the coal-air-limestone reaction. A continual

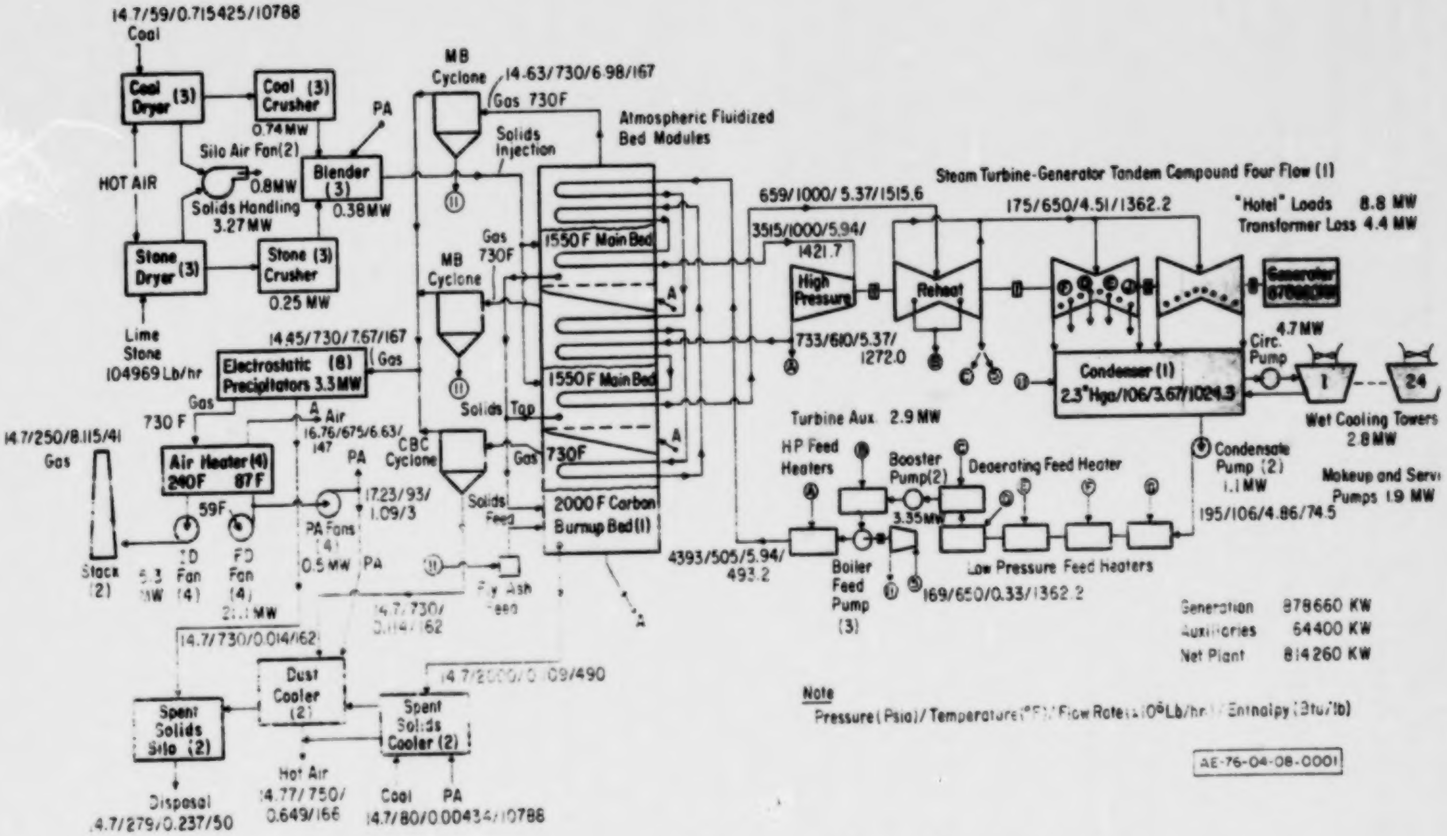

14.7/59/0.715425/10788
Coal
Coal Dryer (3)
Coal (3) Crusher
0.74 MW
Silo Air Fan(2)
0.8MW
HOT AIR
Solids Handling
3.27 MW
PA
Blender (3)
0.38MW
Stone Dryer (3)
Stone (3) Crusher
0.25 MW
Lime Stone
104969 Lb/hr
MB Cyclone
14.63/730/6.98/167
Gas 730F
Solids Injection
Atmospheric Fluidized Bed Modules
Gas 730F
MB Cyclone
1550 F Main Bed
1550 F Main Bed
A
A
14.45/730/7.67/167
Gas
Electrostatic (8) Precipitators 3.3 MW
Gas
730 F
A Air
16.76/675/6.63/147
14.7/250/8.115/41
Gas
Air Heater (4)
240F 87F
59F
PA
17.23/93/1.09/3
CBC Cyclone
Solids Tap
Gas 730F
Solids Feed
2000 F Carbon Burnup Bed (1)
Stack (2)
5.3 MW
ID Fan (4)
FD Fan (4)
2.1 MW
PA Fans (4)
0.5 MW
PA
11
Fly Ash Feed
14.7/730/0.114/162
A
14.7/730/0.014/162
Dust Cooler (2)
14.7/2000/0.109/490
Spent Solids Silo (2)
Spent Solids Cooler (2)
Disposal
14.7/279/0.237/50
Hot Air
14.77/750/0.649/166
Coal PA
14.7/80/0.00434/10788
Steam Turbine-Generator Tandem Compound Four Flow (1)
659/1000/5.37/1515.6
3515/1000/5.94/1421.7
175/650/4.51/1362.2
"Hotel" Loads 8.8 MW
Transformer Loss 4.4 MW
High Pressure
Reheat
Generator
733/610/5.37/1272.0
A
B
C
D
11
4.7 MW
Circ. Pump
Condenser (1)
2.3"Hga/106/3.67/1024.3
1
24
Wet Cooling Towers
2.8 MW
Turbine Aux. 2.9 MW
HP Feed Heaters
Booster Pump(2)
3.35MW
Deaerating Feed Heater
Condensate Pump (2)
1.1 MW
Makeup and Servi
Pumps 1.9 MW
195/106/4.86/74.5
4393/505/5.94/493.2
Boiler Feed Pump (3)
Low Pressure Feed Heaters
169/650/0.33/1362.2
Generation 878660 KW
Auxiliaries 64400 KW
Net Plant 814260 KW
Note
Pressure (Psia)/Temperature (°F)/Flow Rate (10⁶ Lb/hr)/Enthalpy (Btu/lb)
AE-76-04-08-0001

Figure 15. Schematic Diagram of Advanced Steam Cycle--Atmospheric Fluidized Bed

tap of these solids maintains a constant bed inventory of solids. The bed temperature of 1550 F results in maximum sulfur capture. It is also below the ash fusion temperature. Most of the ash will be conveyed by the gas stream as fly ash. The heat exchange surfaces within the bed material experience high overall heat transfer rates as a result of the localized agitation of the bed material. In the carbon burnup cell bed the temperature of 2000 F is too hot for use in superheating or reheating steam in conjunction with the high heat transfer rates. Only water tubes are located in the bed of the carbon burnup cell for the purpose of in-bed fluid dynamic stability.

The gases leaving the beds must be cooled to 730 F for effective fly ash removal from the low sulfur gas streams. This cooling is done by heat transfer to steam superheaters and reheaters and then to economizer surfaces as described above.

The solids fed to the carbon burnup cells comprise the solids tapped from the main beds and that portion (95 percent) of the fly ash collected in the cyclone separators that receives the gas flowing from the main beds.

Flue Gas and Air Supply

The flue gas from the main beds and from the carbon burnup cells at 730 F flow through cyclone separators that remove 95 percent of the solids burden in the gas streams. The hot electrostatic precipitators (ESPs) remove the remaining fine fly ash to the level mandated by emission standards. The hot flue gas next passes through the air preheater, where it is cooled to 240 F. The induced draft (ID) fan assists in this flow and delivers the gas at 250 F to the stack.

Air for combustion passes through the forced draft (FD) fans. About 15 percent of that air is further boosted in pressure by the primary air fans so that it may be used to convey solids into the fluidized bed cells. The main air (A) is heated to 675 F in the air heater and is then routed to the fluidized bed cells. The pressure rise of the forced draft fans is substantially greater than conventional practice because of the flow restrictions imposed by the fluidized beds, their perforated air distribution plates, and the cyclone fly ash separators.

Spent Solids Systems

Spent solids in the form of dry hot granular material are collected from the carbon burnup cell solids tap. Spent solids in the form of dust are collected from the carbon burnup cell cyclone separator and from the ESP. The composition of the spent solids aggregate is 42 percent calcium sulfate, 24 percent unreacted lime, 31 percent ash, and 3 percent unburned carbon. The unreacted lime results from the 100 percent excess in the limestone feed rate as well as the fact that the lime is not 100 percent effective in sulfur capture.

Coolers are provided for the spent solids and dust to supply heated air for the drying of coal and limestone. A small amount of coal is burned in the spent solids cooler to augment this regenerative use of the sensible heat in the spent solids.

Coal and Limestone Systems

Hot air at 750 F from the spent solids system is drawn through the feedstock dryers and storage silos by the silo air fans. The dried coal and limestone are crushed to size, blended, and then conveyed to the AFB main cells by vibrating inclined tables. Primary air is used to assist the flow from the tables down through the many injection needles or tubes in the beds.

Overview

The fluidized main beds scavenge sulfur, and the carbon burnup bed scavenges otherwise lost combustibles from fly ash and solids discharged. The subdivision into four modules ensures that malfunctions in a single AFB system would not result in total plant shutdown. The steam turbine and its support systems are of proven high reliability.

3. MAJOR CYCLE COMPONENTS

Components for steam power plants are specified for continuous operation with flow rates 5 percent greater than the requirement for the 100 percent power. Figure 15 depicts the 100 percent operating point. The major component specifications as well as the balance-of-plant (BOP) components specifications are based on continously sustaining the 5 percent margin. For the steam turbine-generator this operation is at the VWO condition of the main steam throttle control. This customary margin in all components assures purchasers that the entire system will not fall below its intended power rating because of some minor inadequacy in one or more components. The specifications for components will generally not match exactly the stated performances shown in Figure 15.

The design and performance details of the AFB modules and the steam turbine-generator are considered in this section. All remaining equipment would be specified and supplied by an architect-engineer (AE) as BOP materials. Equipment lists for these items are provided under "System Performance and Cost."

Atmospheric Fluidized Bed Modules

The major component of the heat input systems is the AFB module together with its air supply and hot gas cleanup equipment and the solids handling equipment.

In the fluidized bed combustion process, air enters a plenum at the bottom of the cell, flows up through a grid plate that is designed to distribute the air uniformly across the bed, passes through and fluidizes the bed material which envelops a tube bundle, exits from the bed, passes through a convection pass tube bundle located above the bed, and exits from the cell. Coal and limestone are injected into the bed through injection pipes that are arranged to distribute the coal uniformly across the bed plan area. Feeding is continuous in order to provide steady combustion conditions. Spent bed material is continually drained to provide steady bed operating levels. The surfaces submerged in the fluidized bed have exceptionally good heat transfer characteristics. In addition there is no coal ash corrosion of the heat exchange surfaces since the beds operate below the ash fusion temperature and provide a continuously alkaline atmosphere. Fluidized bed combustors require a combustion air supply system, a hot gas cleanup system for removing particulate material entrained in the flue gas, coal and sorbent processing and feeding systems, and a spent bed material removal system.

The spent bed material is alkaline and should be handled in a dry state. Because of its good chemical reactivity and alkalinity, it is considered a chemical by product of the process and can be used in a number of ways. For example, the use of atmospheric fluidized bed dust has been reviewed for application in the neutralization of acid mine runoff, the preparation of fertilizer, in the preparation of alkaline scrubbing solutions for other conventional units. Because of its concentrated iron (magnetite) and alumina content it has been considered as a feedstock for iron and aluminum manufacture. Its practical use as a feedstock for metallurgical processing will depend to some extent on a better understanding of the chemical composition as a function of size distribution in the solids products recovered from the fluidized bed boiler. Regeneration of spent bed material was not considered in this study and requires further development.

Figure 16 shows the equipment for spent bed material removal and cooling. The spent sorbent is transported by a high-temperature vibrating conveyer to an air fluidized bed cooler which cools the material to disposable temperatures of 250 to 300 F. Heat recovered from the cooling of the spent sorbent is used to dry the raw coal and limestone by ducting the coolers' hot discharge air to the dryer units. During plant startup conditions, when hot spent sorbent is not available, the drying units obtain their heat for drying by burning coal in their furnace sections.

The Hot Gas Cleanup section of Figure 16 shows the conventional cyclone separators and ESPs that strip elutriated bed material from the flue gases. Solid material captured in the main bed cyclones is recycled to the 2000 F carbon burnup cell. Material from the carbon burnup cell that is captured in its cyclone separator is removed and cooled by means of an air-fines cooler. Particulate matter captured in the ESPs is removed from the process without cooling since the heat content of this stream is small. It is to be noted that "hot" precipitators at 730 F are used instead of conventional 300 F "cold" precipitators in order to compensate for the low ash resistivities that are encountered with low-temperature, low-sulfur bearing flue gases.

The Air Supply System utilizes forced draft (FD) and induced draft (ID) fans to "push" and "pull" the combustion air through the system. Primary air boost fans are used to provide the high air pressures that are required to inject the coal and limestone into the beds. Regenerative air heaters are utilized to recover flue gas heat and preheat the combustion air; the leakage rate was assigned as 7 percent. This leakage rate is considered to be somewhat optimistic, but obtainable with advanced design. If air leakage rates of less than 10 percent cannot be economically obtained in regenerative air heaters, the use of an extended surface tubular air heater of advanced design is indicated for further study.

A combustion control and safety interlock system is required. A more complicated control system is required with a fluidized bed boiler consisting of four towers with seven combustion beds in each tower and the need for blending and controlling the steam production of four towers. Because of the multiplicity of heat transfer circuits required in this system, a more complex startup system and control valve arrangement is required on the water and steam circuit. Further development is required for steam circuitry and control. Valves and controls for the modules only are included; items needed for a four-tower steam blending system were omitted.

A process flow schematic is presented as Figure 17 which summarizes the detailed heat and mass balances made for each item of equipment at the design specification point. The schematic is for one of four AFB modules.

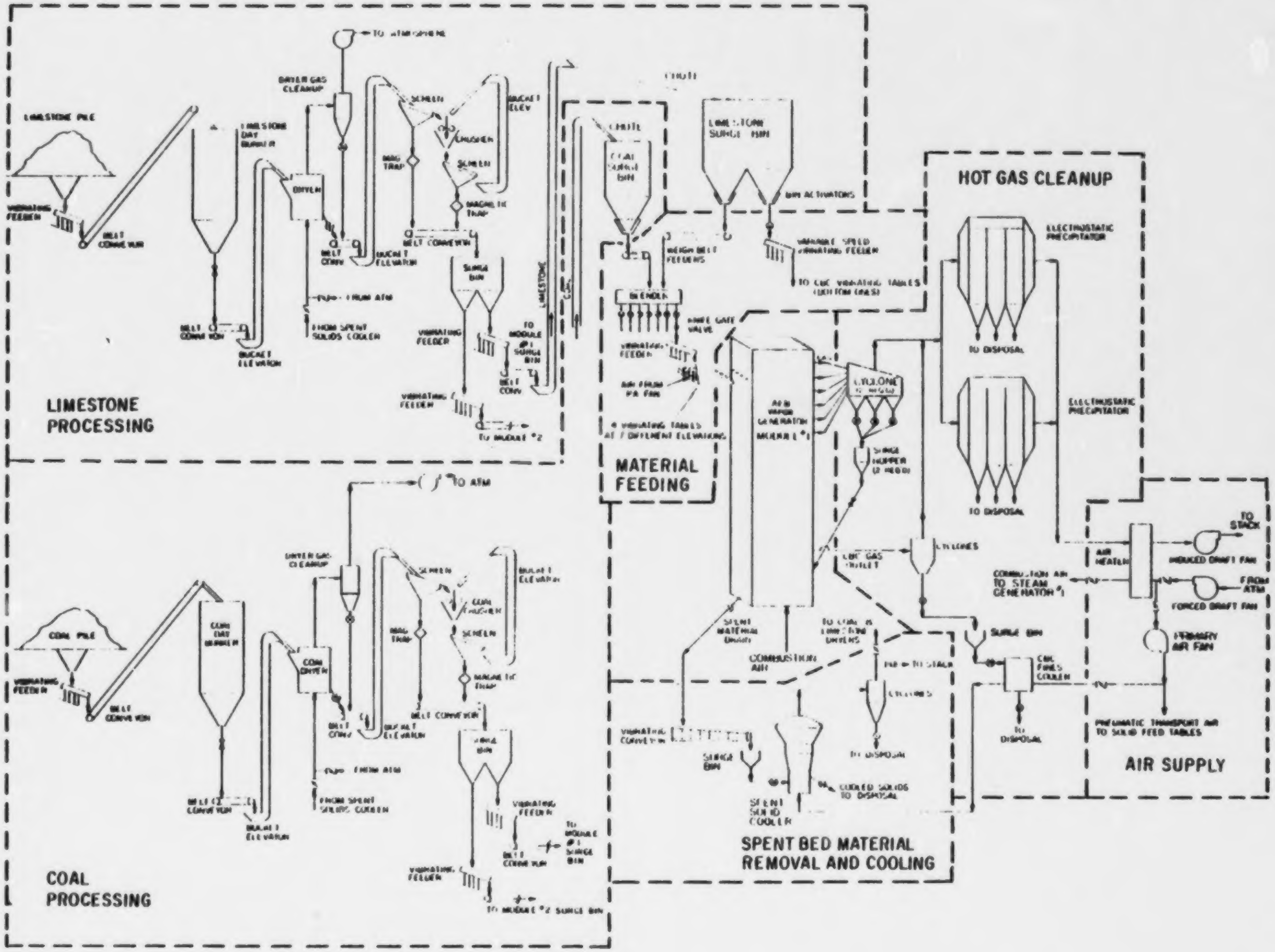

LIMESTONE PILE
VIBRATING FEEDER
BELT CONVEYOR
LIMESTONE DAY BUNKER
BELT CONVEYOR
BUCKET ELEVATOR
DRYER
DRYER GAS CLEANUP
TO ATMOSPHERE
FROM ATM
FROM SPENT SOLIDS COOLER
BELT CONV
BUCKET ELEVATOR
SCREEN
MAG TRAP
CRUSHER
SCREEN
MAGNETIC TRAP
BUCKET ELEV
BELT CONVEYOR
SURGE BIN
VIBRATING FEEDER
TO MODULE #1 SURGE BIN
BELT CONV
VIBRATING FEEDER
TO MODULE #2
LIMESTONE
COAL
LIMESTONE PROCESSING
CHUTE
COAL SURGE BIN
LIMESTONE SURGE BIN
BIN ACTIVATORS
WEIGH BELT FEEDERS
VARIABLE SPEED VIBRATING FEEDER
TO CBC VIBRATING TABLES (BOTTOM ONES)
BLENDER
KNIFE GATE VALVE
VIBRATING FEEDER
AIR FROM PA FAN
4 VIBRATING TABLES AT 7 DIFFERENT ELEVATIONS
MATERIAL FEEDING
AFB VAPOR GENERATOR MODULE #1
CYCLONE
SURGE HOPPER (2 REQD)
HOT GAS CLEANUP
ELECTROSTATIC PRECIPITATOR
TO DISPOSAL
ELECTROSTATIC PRECIPITATOR
TO DISPOSAL
CBC GAS OUTLET
CYCLONES
SPENT MATERIAL DRAIN
TO COAL & LIMESTONE DRYERS
COMBUSTION AIR
TO STACK
CYCLONES
TO DISPOSAL
VIBRATING CONVEYOR
SURGE BIN
SPENT SOLID COOLER
COOLED SOLIDS TO DISPOSAL
SPENT BED MATERIAL REMOVAL AND COOLING
SURGE BIN
CBC FINES COOLER
TO DISPOSAL
AIR HEATER
TO STACK
INDUCED DRAFT FAN
FROM ATM
FORCED DRAFT FAN
COMBUSTION AIR TO STEAM GENERATOR #1
PRIMARY AIR FAN
PNEUMATIC TRANSPORT AIR TO SOLID FEED TABLES
AIR SUPPLY
TO ATM
DRYER GAS CLEANUP
COAL PILE
VIBRATING FEEDER
BELT CONVEYOR
COAL DAY BUNKER
BELT CONVEYOR
BUCKET ELEVATOR
COAL DRYER
FROM ATM
FROM SPENT SOLIDS COOLER
BELT CONV
BUCKET ELEVATOR
SCREEN
MAG TRAP
COAL CRUSHER
SCREEN
MAGNETIC TRAP
BUCKET ELEVATOR
BELT CONVEYOR
SURGE BIN
VIBRATING FEEDER
BELT CONVEYOR
TO MODULE #1 SURGE BIN
VIBRATING FEEDER
TO MODULE #2 SURGE BIN
COAL PROCESSING

Figure 16. AFB Solids Handling and Hot Gas Cleanup Equipment Systems for Two Module Trains (Foster Wheeler)

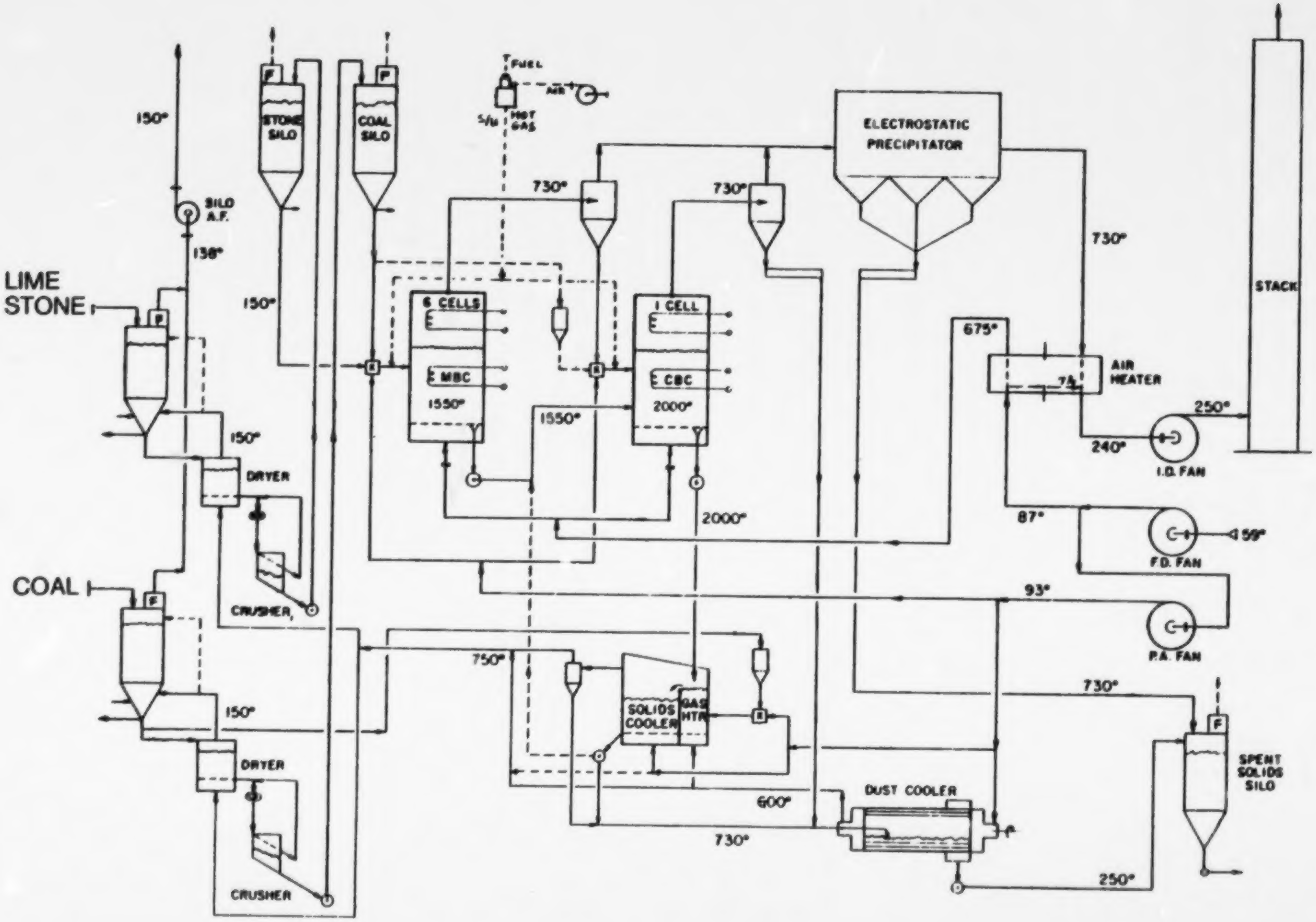

LIME STONE
COAL
150°
SILO A.F.
138°
STONE SILO
COAL SILO
F
150°
150°
150°
DRYER
CRUSHER
DRYER
CRUSHER
FUEL
AIR
S/U
HOT GAS
730°
730°
6 CELLS
MBC
1550°
1550°
I CELL
CBC
2000°
2000°
ELECTROSTATIC PRECIPITATOR
730°
675°
AIR HEATER
250°
240°
I.D. FAN
STACK
87°
F.D. FAN
59°
93°
P.A. FAN
750°
SOLIDS COOLER
GAS HTR
730°
SPENT SOLIDS SILO
600°
DUST COOLER
730°
250°

Figure 17. Atmospheric Fluid Bed Steam Generator — Process Flow Schematic (Foster Wheeler).

Figure 18 shows a design concept of one AFB tower for steam generation. This concept was developed to a sufficient level of detail to reveal all major engineering problems and to permit realistic cost evaluations. The unit is 12 ft x 34 ft x 180 ft tall and weighs 800 tons in operation. It includes economizing, superheating, and reheating services in the beds and in convection spaces above the beds. The tubes are of conventional materials, and tube bundles were sized to be shipped by rail. Fuel is injected into the beds through needles, each servicing about 10 square feet of main bed area. The bottom unit is the carbon burnup cell (CBC). There are six main cells stacked on top of the CBC. The air and flue gas ducts taper from bottom to top in proportion to the local gas flow. The heat absorption in each AFB module is shown in Figure 19. At the extreme left appear the total heat to steam for each cell (SHS, RHS duty). The fluidized bed heat exchange surfaces have an overall heat transfer coefficient of 40 Btu per hr ft^2 F. The convection surfaces above the bed have coefficients one-third to one-quarter those in the bed. Table 39 details the heat exchanger surfaces shown in Figure 19. Table 40 summarizes the basic requirement for materials which lead to Item 1 in Table 41 where the selling prices of the AFB module are derived from the component weights. The costs of module auxiliaries are presented with the major component equipment lists under "Plant Cost Estimates."

The performance evaluation for the overall boiler system shows a boiler efficiency of 87.92 percent for heat to steam divided by the total coal fired. If additional heat recovery from spent solids could completely displace coal burned to supplement drying of coal and limestone, then a boiler efficiency of 88.46 percent would be realized.

Prime Cycle

The major component for the prime cycle is the steam turbine-generator. The selected unit was a General Electric Tandem compound turbine with 4-flow exhaust using 33.5-in. last-stage buckets. The rating was selected to reach the maximum allowed steam flow through the last-stage buckets at the VWO and overpressure condition. This selection is typical of current utility purchases. An outline drawing, Figure 20, shows the four turbine shells and the generator having an overall length of 173 ft. The performance of the steam turbine-generator is inseparable from many of the BOP components that are part of the prime cycle heat balance. Figure 21 presents the heat balance for the 100 percent operating point for the entire prime cycle. The heat-to-steam is 6286.7 MBtu/hr. The gross efficiency of the prime cycle is 43.9 percent.

The condenser back pressure of 2.3 in. Hga resulted from an economic optimization of the turbine and heat rejection system in combination. Although the cooling tower was not a major component, its specifications are given in Table 42 insofar as they impact directly on the steam turbine prime cycle performance.

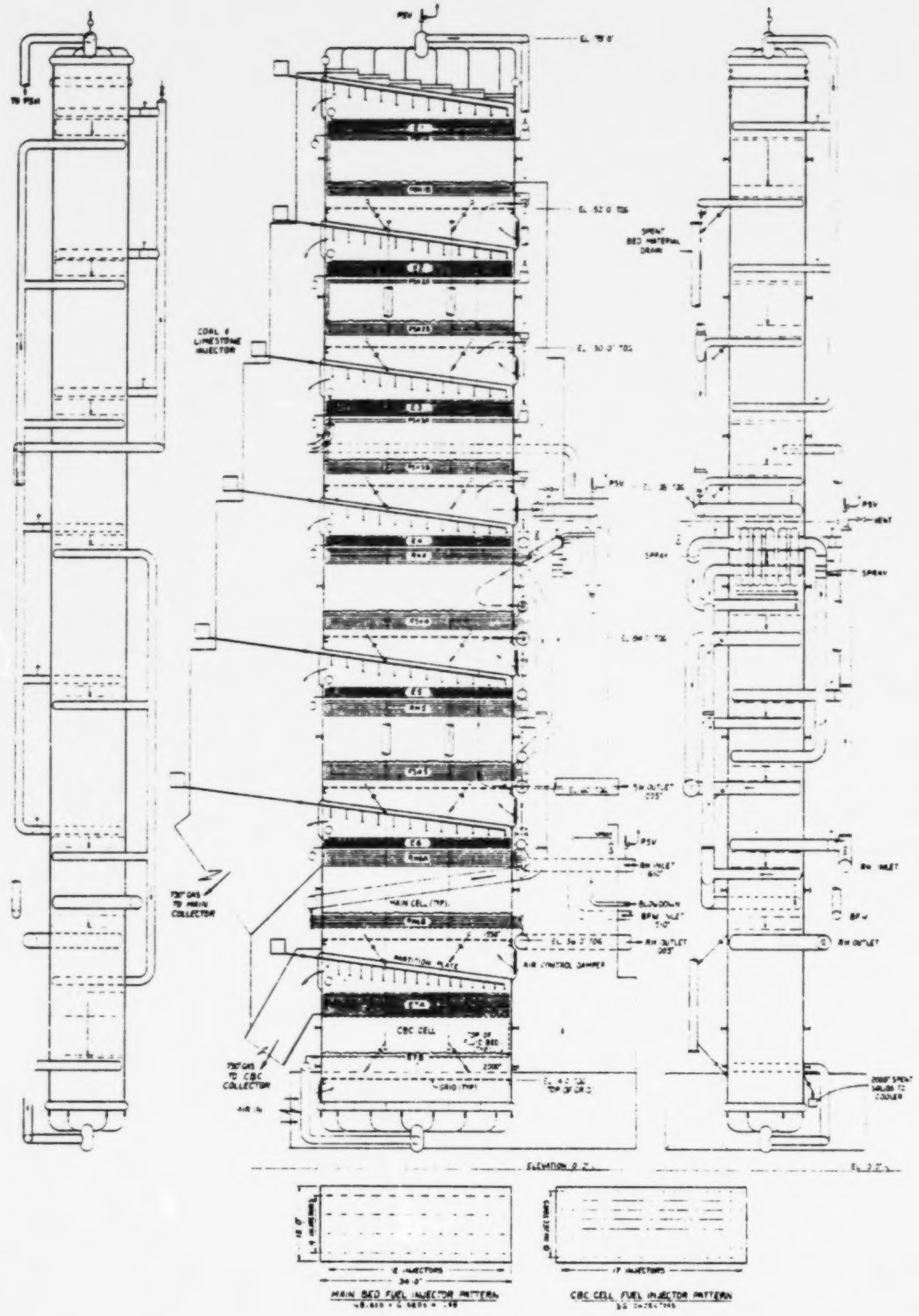

TO PSH
PSV
COAL & LIMESTONE INJECTOR
SPENT BED MATERIAL DRAIN
PSV
VENT
SPRAY
SPRAY
SH OUTLET
PSV
RH INLET
BLOWDOWN
BFW INLET
RH OUTLET
RH INLET
BFW
RH OUTLET
E6
MAIN CELL (TYP)
PARTITION PLATE
AIR CONTROL DAMPER
E7A
CBC CELL
TOP OF FLUID BED
E7B
GRID (TYP)
TOP OF GRID
730° GAS TO MAIN COLLECTOR
730° GAS TO CBC COLLECTOR
AIR IN
2000° SPENT SOLIDS TO COOLER
ELEVATION 0
18 INJECTORS
17 INJECTORS
MAIN BED FUEL INJECTOR PATTERN
CBC CELL FUEL INJECTOR PATTERN

Figure 18. Advanced Steam Cycle — Atmospheric Fluidized Bed Boiler (Foster Wheeler)

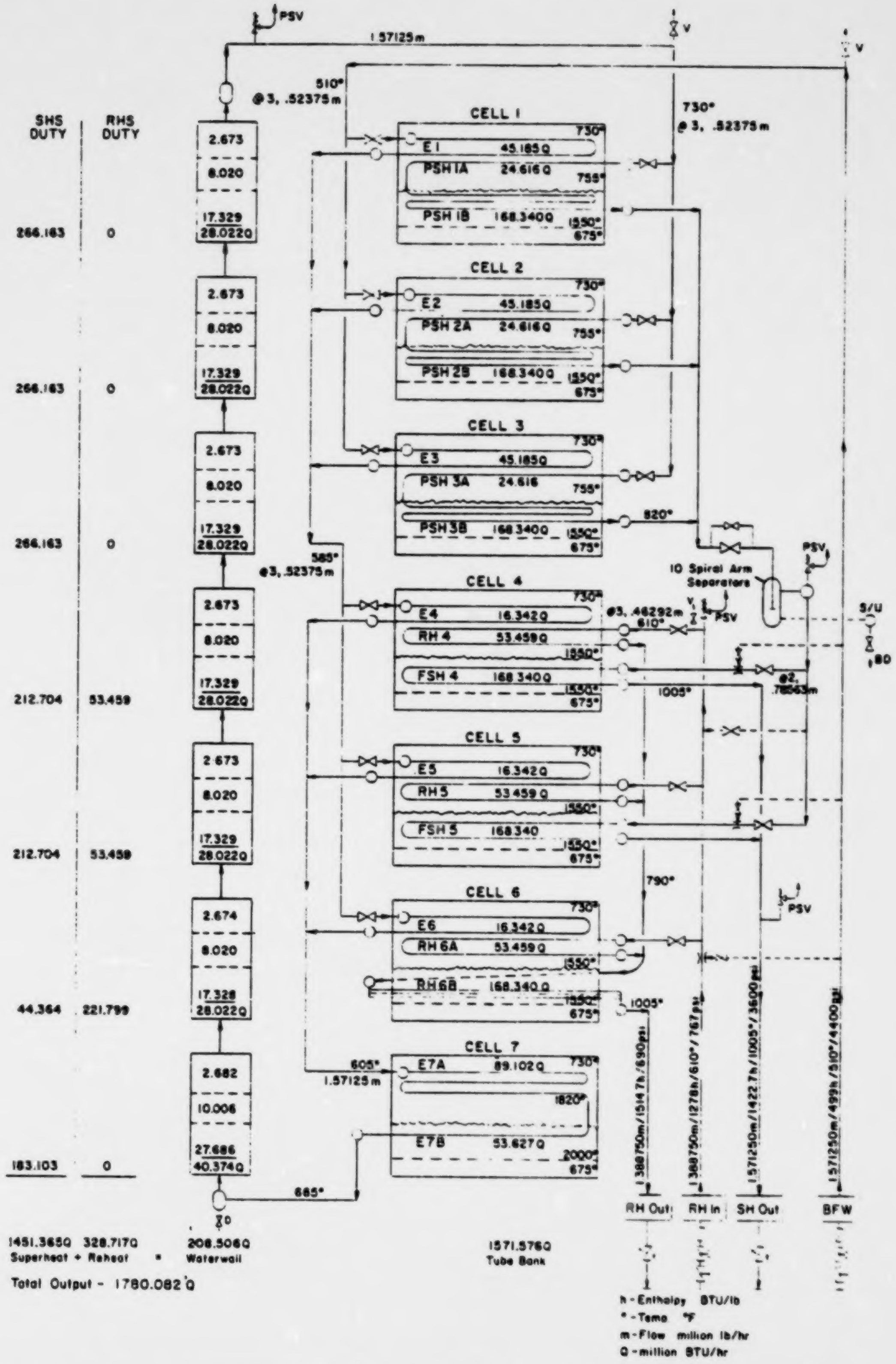

PSV
1.57125m
V
V
510°
@3, .52375m
730°
@3, .52375m
SHS DUTY
RHS DUTY
CELL 1
730°
E1 45.185Q
PSH 1A 24.616Q
755°
PSH 1B 168.340Q
1550°
675°
2.673
8.020
17.329
28.022Q
266.163
0
CELL 2
730°
E2 45.185Q
PSH 2A 24.616Q
755°
PSH 2B 168.340Q
1550°
675°
266.163
0
CELL 3
730°
E3 45.185Q
PSH 3A 24.616
755°
PSH 3B 168.340Q
1550°
675°
820°
266.163
0
585°
@3, .52375m
10 Spiral Arm Separators
PSV
CELL 4
730°
E4 16.342Q
RH 4 53.459Q
1550°
FSH 4 168.340Q
1550°
675°
@3, .46292m
610°
V
PSV
S/U
80
@2, .78063m
1005°
212.704
53.459
CELL 5
730°
E5 16.342Q
RH5 53.459Q
1550°
FSH 5 168.340
1550°
675°
212.704
53.459
790°
PSV
CELL 6
730°
E6 16.342Q
RH 6A 53.459Q
1550°
RH 6B 168.340Q
1550°
675°
1005°
2.674
8.020
17.328
28.022Q
44.364
221.799
CELL 7
605°
1.57125m
E7A 89.102Q
730°
1820°
E7B 53.627Q
2000°
675°
2.682
10.006
27.686
40.374Q
183.103
0
685°
D
1.388750m/1514.7h/690psi
1.388750m/1278h/610°/767psi
1.571250m/1422.7h/1005°/3600psi
1.571250m/499h/510°/4400psi
RH Out
RH In
SH Out
BFW
1451.365Q 328.717Q
Superheat + Reheat
=
208.506Q
Waterwall
1571.576Q
Tube Bank
Total Output - 1780.082Q
h - Enthalpy BTU/lb
° - Temp °F
m - Flow million lb/hr
Q - million BTU/hr

Figure 19. Advanced Steam – PFB Circuit Absorption Diagram

Table 39

AFB MODULE HEAT EXCHANGER SURFACE DATA

Cell	Bank	So(ft^2)	Øo	Ns	St	Sl	BC +	Nr	1/1	Loops	Øin/Øout	$Ø_1/Ø_2/Ø_3$
1	E1	12818	1-1/4	96	3	1-1/2	31-1/4	12	1	6	12/12	12/12/12
	PSH1A	2136	1-1/4	96	3	1-1/4	6-1/4	2+	2	1/2	14/-	14/14/-
	PSH1B	6409	1-1/4	96	3	1-5/8	20-3/4	6	2	1-1/2	-/14	2@ 10/24/20
2	E2	12818	1-1/4	96	3	1-1/4	31-1/4	12	1	6	12/12	12/12/12
	PSH2A	2136	1-1/4	96	3	1-1/4	6-1/4	2+	2	1/2	14/-	14/14/-
	PSH2B	6409	1-1/4	96	3	1-5/8	20-3/4	6	2	1-1/2	-/14	2@ 10/24/20
3	E3	12818	1-1/4	96	3	1-1/4	31-1/4	12	1	6	12/12	12/12/12
	PSH3A	2136	1-1/4	96	3	1-1/4	6-1/4	2+	2	1/2	14/-	14/14/-
	PSH3B	6409	1-1/4	96	3	1-5/8	20-3/4	6	2	1-1/2	-/14	2@ 10/24/20
4	E4	7477	1-1/4	96	3	1-1/4	21-1/4	8	1	4	12/12	12/12/12
	RH4	6836	2	48	6	2-1/4	38	8	4	1	18/20	24/18/20/24
	FSH4	7976	1-3/4	64	4-1/2	2-1/4	37-1/4	8	4	1	20/24	20/24/24
5	E5	7477	1-1/4	96	3	1-1/4	21-1/4	8	1	4	12/12	12/12/12
	RH5	6836	2	48	6	2-1/4	38	8	4	1	18/20	24/18/20/24
	FSH5	7976	1-3/4	64	4-1/2	2-1/4	37-1/4	8	4	1	20/24	20/24/24
6	E6	7477	1-1/4	96	3	1-1/4	21-1/4	8	1	4	12/12	12/12/12
	RH6A	6836	2	48	6	2-1/4	38	8	4	1	18/20	24/18/20/24
	RH6B	6409	1-3/4	64	4-1/2	2-1/4	28-3/4	6	6	1/2	24/28	24/32
7	E7A	15131	1-3/4	64	4-1/2	1-3/4	54-1/4	15+	1	7-1/2	12/-	12/12/-
	E7B	997	1-3/4	64	4-1/2	2-1/4	4	1	1	1/2	-/14	-/14
	WW	15209~	1-1/4	736	1-1/2	fin	-	1	1	1/2	14/14	14/24/16 @ 6 in 16 @ 6/24/14 out

Notes:

So - Installed Surface - Ft^2
Øo - Tube O.D. - inches
Ns - No. Sections wide
St - Side spacing - inches
Sl - Back spacing - inches (staggered pitch)
BC - Bundle clearance - inches (includes one S_L extra for supports)
Nr - Number runs
1/1-loop in loop
Øin/Øout - header diameter inches
$Ø_1/Ø_2/Ø_3$ - Header, Tx pipe sizes - inches

Table 40

AFB MODULE WEIGHT BREAKDOWN
RAW HEAT EXCHANGER SURFACE MATERIAL, TONS

HX SURFACE	TONS	CS	T2	T22	T304
E1, 2, 3	133.3	133.3			
E4, 5, 6	77.9	77.9			
E7A, B	77.8	72.4	5.4		
WW	70.0		58.7	11.3	
PSH1, 2, 3	114.1		23.6	90.5	
FSH4, 5	121.7				121.7
RH4, 5, 6	111.1			77.9	33.2
Σ	705.9	283.6	87.7	179.7	154.9
%	100	40.2	12.4	25.5	21.9

Table 41

AFB MODULE WEIGHT AND COST BASIS MID-1975

1. Heat Transfer Elements and Pressure Parts

Material	Tons	1975 $/Ton	1975 M$
CS	447.6	2848	1.275
T2/P2	183.7	3144	.578
T22/P22	191.5	3774	.723
TP304	202.1	11771	2.379
IN601	5.2	13300	.069
Hast. X	1.6	24321	.039
	1031.6		5.063

2. Special FBBU Items

FBBU Item	Tons	1975 $/Ton	1975 M$
Injector needles	32.55	6455	.210
Fluidization grilles	35.70	6528	.233
Solids line	60.00	3300	.198
Solids valves	8	13750	.110
	136.25		.751

3. Control System

Item	1975 Rate	Tons	1975 M$
Startup, steam valves	33 @ 3960	17.4	.131
Combustion elements	7 @ 11000	3.5	.077
Bed air dampers	7 @ 4400	5.6	.031
			.239
CC & SIS (Controls, operators, etc.)			.435
		26.50	.724

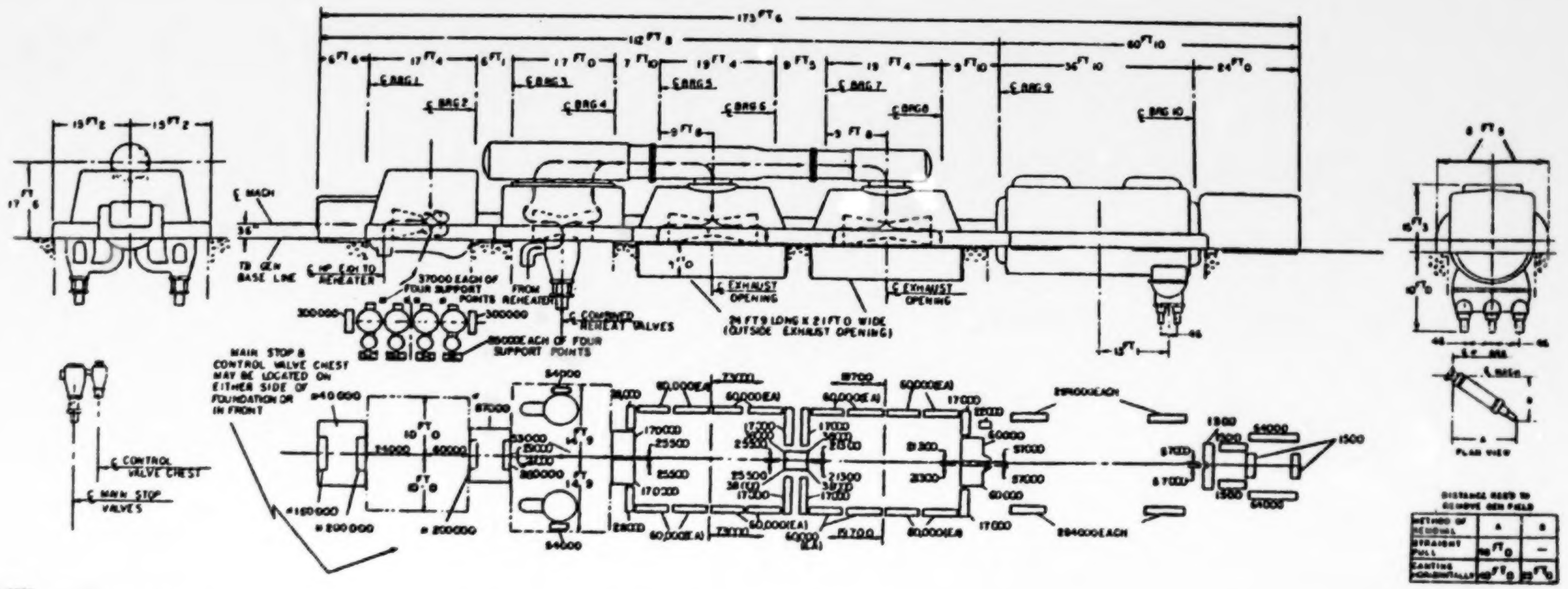
4. Miscellaneous Items

Item	(Unit) or Tons	1975 $/Ton	1975 M$
Flues and ducts	330	1430	.472
Flue and duct insulation	76.5	2200	.168
Boiler lag and sheath	62.5	880	.055
Buckstays and braces, etc.	90.0	1100	.099
Misc. pipe, springs, joints	18.0	5500	.099
	577.0		.893

262.6 tons on boiler

SUMMARY

	Tons	M$(75)
1. Surface & Pressure Parts	1031.6	5.063
2. FBBU Items	136.3	.751
3. Control Systems and Valves	26.5	.724
4. Attached Flue and Duct	92.1	.138
5. Boiler Lag and Sheath	62.5	.055
6. Buckstays, Braces, Hangers	90.0	.099
7. Miscellaneous Piping, Small Valves, Supports, etc.	18.0	.099
	1457.0	6.930
-Controls		-.724
		6.206


173 FT 6
12 FT 8
60 FT 10
6 FT 6
17 FT 4
6 FT 1
17 FT 0
7 FT 10
19 FT 4
9 FT 5
19 FT 4
3 FT 10
36 FT 10
24 FT 0
℄ BRG 1
℄ BRG 2
℄ BRG 3
℄ BRG 4
℄ BRG 5
℄ BRG 6
℄ BRG 7
℄ BRG 8
℄ BRG 9
℄ BRG 10
19 FT 2
17 FT 6
℄ MACH
36"
TB GEN BASE LINE
℄ HP EXH TO REHEATER
37000 EACH OF FOUR SUPPORT POINTS
FROM REHEATER
℄ COMBINED REHEAT VALVES
85000 EACH OF FOUR SUPPORT POINTS
300000
℄ EXHAUST OPENING
24 FT 9 LONG X 21 FT 0 WIDE (OUTSIDE EXHAUST OPENING)
MAIN STOP & CONTROL VALVE CHEST MAY BE LOCATED ON EITHER SIDE OF FOUNDATION OR IN FRONT
℄ CONTROL VALVE CHEST
℄ MAIN STOP VALVES
8 FT 9
15 FT 3
10 FT 0
PLAN VIEW
60,000(EA)
284000 EACH
DISTANCE REQD TO REMOVE GEN FIELD
METHOD OF REMOVAL
STRAIGHT PULL
CANTING HORIZONTALLY

NOTES

1. STEAM CONDITIONS 3500PSIG-1000/1000 °F REHEAT WITH 33½IN LAST STAGE BUCKETS
2. HEAVIEST PIECE DURING ERECTION - (GENERATOR STATOR) 760000 LBS
HEAVIEST PIECE AFTER ERECTION - (GENERATOR FIELD ROTOR 180000 LBS
3. 160000 & 200000 LB LOADINGS DO NOT OCCUR SIMULTANEOUSLY BUT ARE SUPERIMPOSED ON 40000 LB LOAD 160000 LB LOAD IS ZERO FOR NORMAL OPERATION FOR FULL VALUE OF 160000 LB LOAD 200000 LB LOAD IS ZERO
4. THE COMBINED REHEAT VALVE ARRANGEMENT INCLUDES THE REHEAT STOP AND INTERCEPT VALVES
5. SHAFT ROTATION IS CLOCKWISE WHEN VIEWED FROM COLLECTOR END OF GENERATOR
6. LOAD VALUES SHOWN ARE FOR TURBINE-GENERATOR UNIT ONLY ADDITIONAL LOAD CONTRIBUTED BY CONDENSER NOT INCLUDED
7. DISTANCE REQUIRED TO REMOVE MAJOR PARTS - NOT INCLUDING SLINGS -

A GENERATOR STATOR - 14 FT 3 FROM TB-GEN BASE LINE WITHOUT TERMINAL BOX ATTACHED
B GENERATOR COOLERS - 19 FT 0 IN HORIZONTALLY FROM VERTICAL ℄ OF GEN

8. THIS OUTLINE SHALL NOT BE USED FOR CONSTRUCTION PURPOSES THE GENERAL EQUIPMENT ARRANGEMENT, DIMENSIONS AND LOADINGS ARE TO BE CONSIDERED PRELIMINARY AND SUBJECT TO LATER MODIFICATION
9. RECOMMENDED MINIMUM CRANE HOOK HEIGHT ABOVE TB. GEN BASE LINE - 35 FT 7 IN
10. RECOMMENDED MINIMUM FOUNDATION HEIGHT - 40 FT 0 IN
11. THE HORIZONTAL FORCES ACTING AT THE KEYS INCLUDE A SEISMIC FACTOR OF 0.188.

Figure 20. Preliminary Outline – Steam Turbine

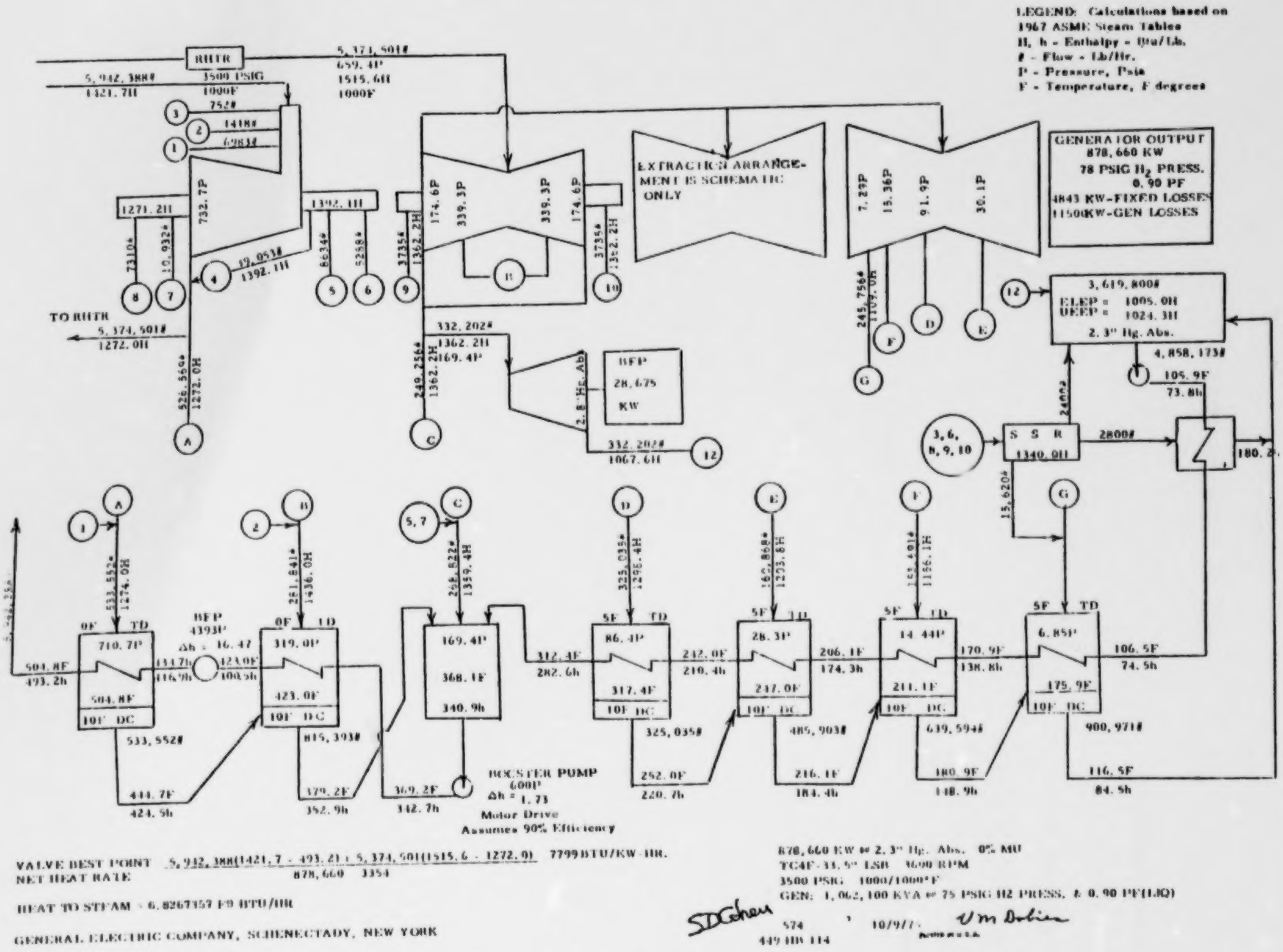

LEGEND: Calculations based on
1967 ASME Steam Tables
H, h - Enthalpy - Btu/Lb.
# - Flow - Lb/Hr.
P - Pressure, Psia
F - Temperature, F degrees
GENERATOR OUTPUT
878,660 KW
78 PSIG H2 PRESS.
0.90 PF
4843 KW-FIXED LOSSES
1150 KW-GEN LOSSES
RHTR
5,942,388#
1421.7H
3500 PSIG
1000F
5,374,501#
659.4P
1515.6H
1000F
TO RHTR
5,374,501#
1272.0H
732.7P
1271.2H
1392.1H
7310#
10,932#
19,053#
1392.1H
8634#
5258#
752#
1418#
6983#
526,569#
1272.0H
174.6P
339.3P
339.3P
174.6P
3735#
1362.2H
3735#
1362.2H
249,256#
1362.2H
332,202#
1362.2H
169.4P
2.8" Hg. Abs
BFP
28,675
KW
332,202#
1067.6H
EXTRACTION ARRANGE-
MENT IS SCHEMATIC
ONLY
7.29P
15.36P
91.9P
30.1P
245,756#
1109.0H
3,619,800#
ELEP = 1005.0H
UEEP = 1024.3H
2.3" Hg. Abs.
4,858,173#
105.9F
73.8h
S S R
1340.0H
2400#
2800#
15,620#
180.2
3,6,
8,9,10
533,552#
1274.0H
281,841#
1436.0H
258,822#
1359.4H
325,035#
1298.4H
162,868#
1203.8H
152,491#
1156.1H
0F TD
710.7P
504.8F
10F DC
BFP
4393P
Δh = 16.47
0F TD
319.0P
423.0F
10F DC
169.4P
368.1F
340.9h
5F TD
86.4P
317.4F
10F DC
5F TD
28.3P
247.0F
10F DC
5F TD
14.44P
211.1F
10F DC
5F TD
6.85P
175.9F
10F DC
504.8F
493.2h
533,552#
444.7F
424.5h
815,393#
379.2F
352.9h
369.2F
342.7h
312.4F
282.6h
325,035#
252.0F
220.7h
242.0F
210.4h
485,903#
216.1F
184.4h
206.1F
174.3h
639,594#
180.9F
148.9h
170.9F
138.8h
900,971#
116.5F
84.5h
106.5F
74.5h
BOOSTER PUMP
600P
Δh = 1.73
Motor Drive
Assumes 90% Efficiency
VALVE BEST POINT 5,942,388(1421.7 - 493.2) + 5,374,501(1515.6 - 1272.0) 7799 BTU/KW-HR.
NET HEAT RATE 878,660 3354
HEAT TO STEAM = 6.8267357 E9 BTU/HR
GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK
878,660 KW @ 2.3" Hg. Abs. 0% MU
TC4F-33.5" LSB 3600 RPM
3500 PSIG 1000/1000°F
GEN: 1,062,100 KVA @ 75 PSIG H2 PRESS. & 0.90 PF(LIQ)
SDCohen
574
449 HB 114
10/9/77
VmDobian

Figure 21. AFB Steam Cycle Heat Balance — 100% Output

Table 42

COOLING TOWER PERFORMANCE

Design heat duty	3,851 MBtu/hr
Wet bulb	51.5 F
Condensing at 2.3 in. Hga	105.9 F
Hot water to tower	100.9 F
Cold water return	70.2 F
Range	30.7 F
Approach	18.7 F
Water flow	250,909 gal/min
Fan power	2.78 MW
Pump power	4.73 MW
Cells	24

Each cell: 36 feet long, 75 feet wide, 47 feet high, 1 fan

Materials of Construction

Steam turbines operating at design steam temperatures of 1000 F have demonstrated a high degree of reliability and utilize materials with a long history of development and service.

Buckets are subjected to centrifugal forces, steam forces, vibratory forces, thermal stresses and erosion from wet steam. Alloys are chosen on the basis of strength at operating conditions, erosion and corrosion resistance, damping properties, and ease of machinability. A 12 percent Cr alloy is a typical selection.

Turbine rotors and wheels are subjected to bucket loadings and must have high resistance to creep and rupture and good thermal stability to resist bowing. The material is selected on the basis of yield, tensile, creep, and rupture strenghts, transistion temperature hardness and impact strength, and its resistance to erosion and corrosion due to normal steam chemistry. Alloy steels are typically used.

Nozzle diaphragms must perform over a wide range of temperature and pressure conditions and withstand steady-state thermal and pressure loadings, differential expansion stresses, and cyclic thermal stresses. In addition the material must be fully weldable and produce sound castings. The material must also have good creep and rupture strength and be resistant to erosion and corrosion. A 12-percent Cr alloy choice is typical. The high-pressure shell or casing must contain the high-pressure steam and resist creep in longtime service as well as being resistant to erosion and corrosion. Castability and weldability are important requirements. Alloy steels are used. Materials for valve bodies are similar to those used for shells and are selected on the same bases of creep and rupture, weldability, stability, and resistance to erosion and corrosion.

With periodic repair and replacement of some parts, thirty years of operation can be expected for the turbine. For the buckets, each turbine stage is analyzed for stresses and frequencies under the specific operating conditions, and allowable stresses are established from results of laboratory testing on creep, rupture, fatigue, and erosion, corrosion resistance, and experience. Rotors and wheels are sized on the basis of torque, plus centrifugal and bending stresses, and are carefully analyzed for critical speeds. When major parameters are established, they are analyzed in detail for fillets, grooves, balancing provisions and contours. Each turbine diaphragm is analyzed for stresses, and the results of extensive laboratory testing are used to establish the allowable stresses. For the shells, the analysis starts with a pressure stress calculation and then is refined for thermal stresses with stress concentrations taken into account. The design procedure for valves likewise analyzes for stress concentration points and provides modifications to account for both steady-state and transient conditions. The thermal stresses are limited by establishing allowable rates of heating and cooling.

In the AFB, coal combustion occurs in a bed of limestone which operates at 1550 F. The materials selected for the various temperature ranges within the AFB at 3500 psig are carbon steel for 850 F maximum temperatue, 1/2 chrome-1/2 molybdenum alloy steel (T2) for 950 F maximum temperature, 2-1/4 chrome alloy steel (T22) for 980 F maximum temperature in thick sections and 1100 F in thin sections, and 304 stainless steel (T304) for maximum temperatures of 1200 F. At the reduced pressure of 700 psi for reheater service T22 would be used for 1075 F maximum and T304 for 1360 F maximum.

Design lifetimes are based on the ASME Power Boiler Code to give an estimated 30-year life. This involves assessment of tensile strength, yield strength, creep, and rupture strength. No detailed investigation was made of corrosion, erosion, or fouling rates, and it was judged that conservative procedures for selected boiler metals would result in the selection of metals adequate for the projected life. The rationale was that internal corrosion was not expected to be a problem and the small amount of external oxidation, sulfiding, and wastage would be compensated by conservative design. External fouling was not considered.

These judgments are based on extensive experimental data on hot corrosion of boiler tube materials. There is in fact good reason to believe that corrosion in fluidized bed combustion systems for the lower temperature steam tubes will be much less severe than in conventional pulverized-coal-fired units. However, there may be a serious corrosion problem in the hotter components of the system.

The ash particles formed at the relatively low fluidized bed combustion temperature are soft and friable compared with the fused ash particles generated in the high-temperature pulverized coal flames of a conventional furnace. No erosion has been reported in pilot scale tests of fluidized bed combustors so that this does not appear to present a significant problem.

Fouling on boiler tubes may become a problem, depending on the ash composition of the coal, its reaction with the bed sorbent, and the operating temperature. If the problem proves to be severe, there may be ways of reducing it by modifications in operating temperatures or by the use of fuel additives.

The steam turbine represents a mature technology, and significant materials problems should not be anticipated. The fluidized bed system does, however, have some potential problem areas. The principal one is hot corrosion, and it will be necessary to run tests for long periods with a variety of coals and tube materials used over a wide range of temperatures for a more complete understanding. There are several options to reduce hot corrosion, including the development of more corrosion-resistant materials or the use of coatings.

4. PLANT ARRANGEMENT

Plot Plan

The plant arrangement on its plot is based on storage of a 60-day supply of coal and a capacity to hold ash for 15 days. A series of ponds contain runoff water from the site and provide for treatment of all water returned to the North River. The basic plot dimensions are one-half mile by three-tenths of a mile.

Figure 22 shows the total plant area of 108 acres in the small section, and the main area in detail. Coal is received by rail and is unloaded to two conical storage piles. The compacted dead storage coal pile is 60 ft high with a base measuring about 1240 ft by 420 ft. This stores 424,000 tons of coal for recovery by use of dozer tractors. Two conical live coal storage piles are provided with a base diameter of about 315 ft. These piles contain a total of 114,700 tons of coal with 27,000 ton available by gravity feed through under-pile vibrating feeders. Limestone is stored in a single storage pile of 135,000-ton total capacity with 6,720 tons available as live feed by gravity flow to the under-pile vibrating feeders. These feeders load a conveyor to the coal cascade. At that point magnetic separators remove tramp iron, and oversized coal is diverted to the crushers for size reduction prior to distribution. The coal and the limestone are then dried, passed through grinders, and blended. There are three trains of equipment from the cascade to the delivery of dried and blended feedstock. Any one of the three sets may be out of service without disabling the plant. The feedstock is conveyed to pairs of AFB modules on each side of the turbine building. The dry and cooled spent solids are conveyed to the 15-day ash storage bins at the lower left for loading on railroad cars. The 24 cells of wet cooling towers are set apart from the rest of the plant in the upper right corner.

General Arrangement

The arrangement of the four AFB modules about the turbine building are shown in Figure 23. This arrangement followed a need to keep main steam lines short in anticipation of use of very high steam temperatures. The ground elevation view shows the air path through the FD fan and the air preheater and then around the lower outside of the AFB to the end next to the turbine building. The 51-ft elevation view shows the path of the flue gas through the ESP, the air preheater, and the induced draft fan, and thence to the stack.

Plant Elevation

The plant elevation view through the turbine building and one AFB is presented in Figure 24. The seven-cell stack of fluidized beds stands]92 ft high. Air is fed upward from the right, and flue gas flows downward on the left side of the AFB module to the cyclone separator. The flue gas passes through the ESPs, the air heater, and the ID fan, and to the stack.

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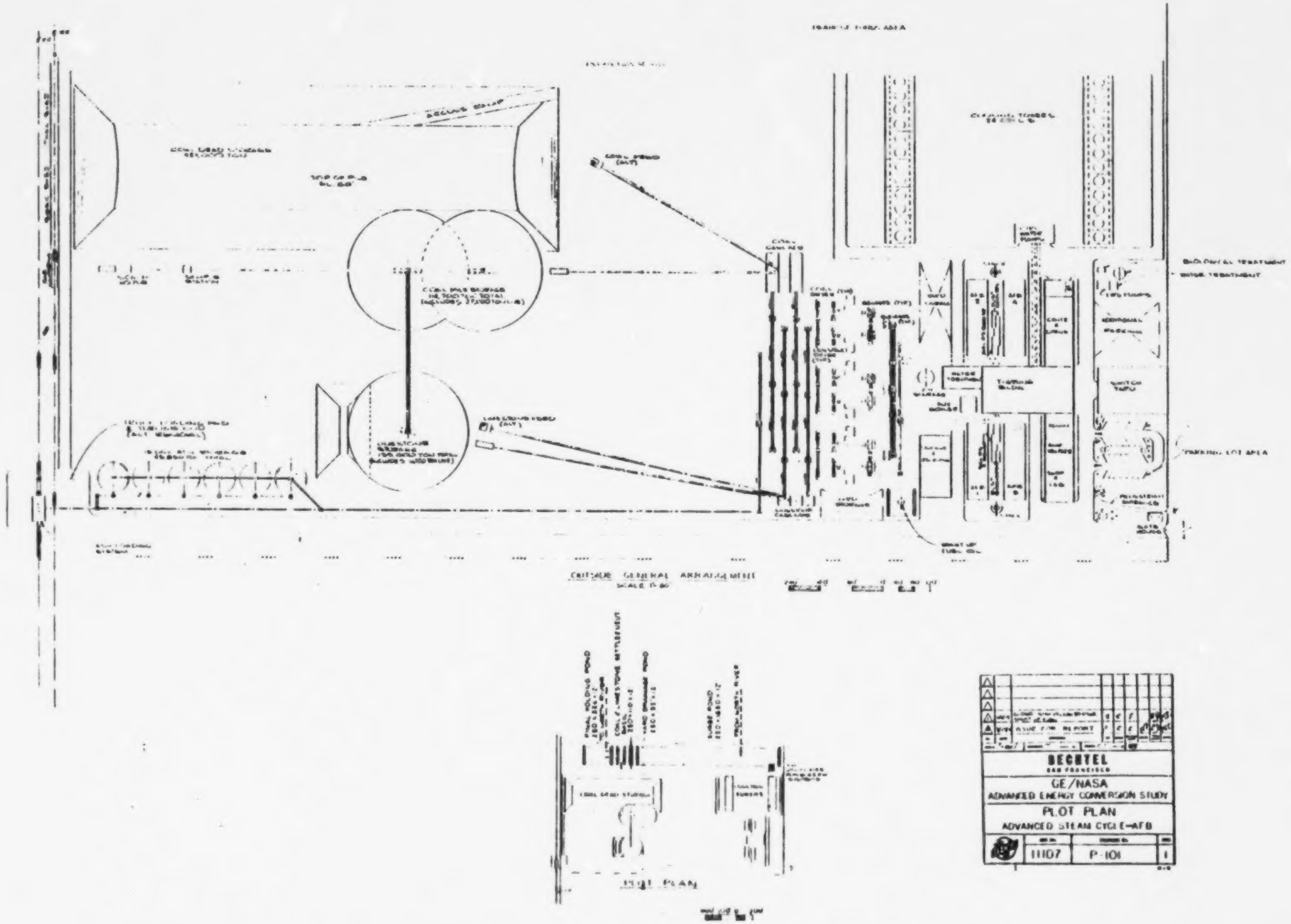
BIOLOGICAL TREATMENT
WATER TREATMENT
PARKING LOT AREA
OUTSIDE GENERAL ARRANGEMENT
PLOT PLAN
ISSUE FOR REPORT
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
PLOT PLAN
ADVANCED STEAM CYCLE–AFB
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Figure 22. Plot Plan Advanced Steam Cycle – Atmospheric Fluidized Bed (Bechtel)

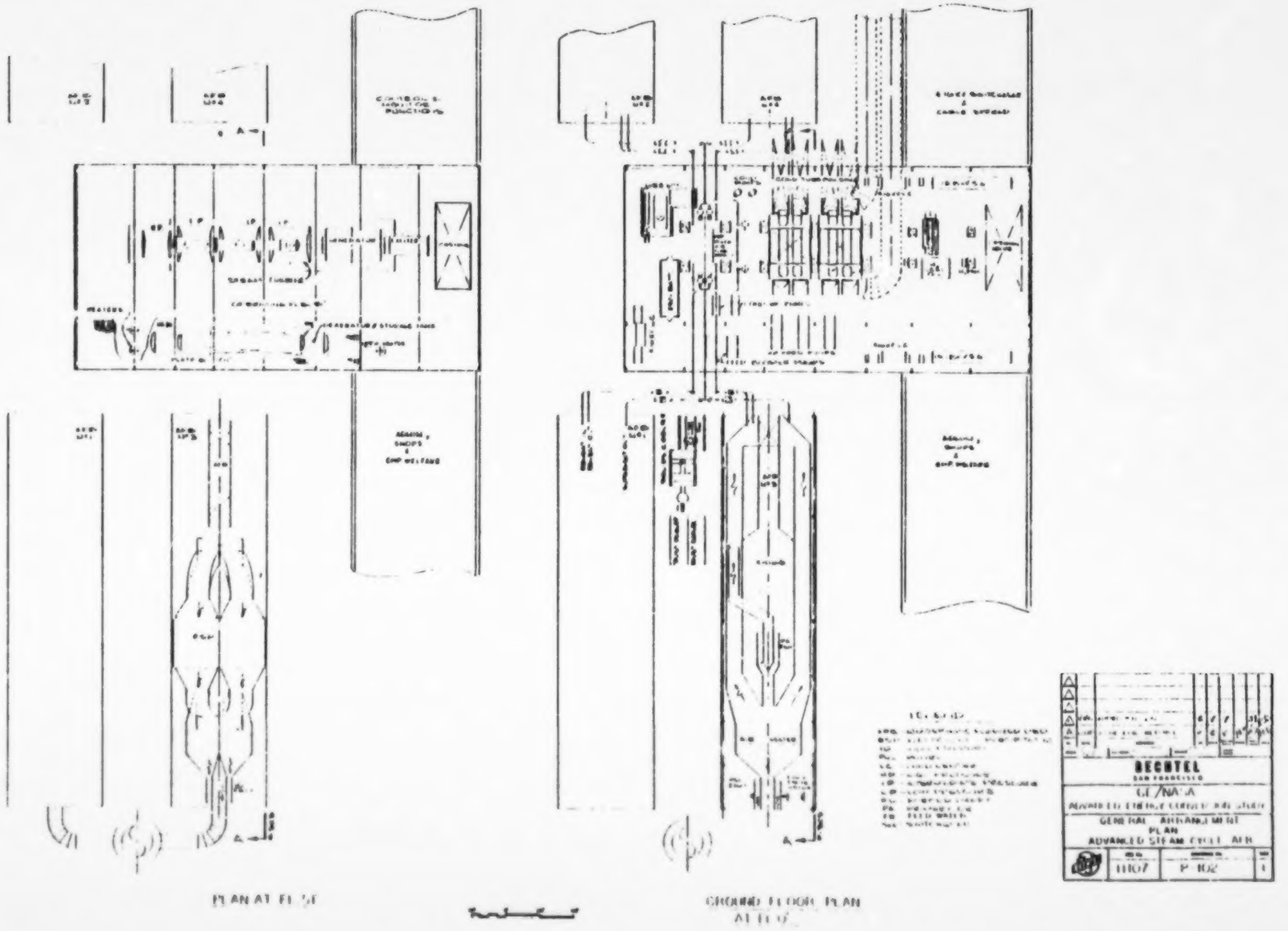
PLAN AT EL 51'
GROUND FLOOR PLAN
AT EL 0'
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
GENERAL ARRANGEMENT
PLAN
ADVANCED STEAM CYCLE AFB
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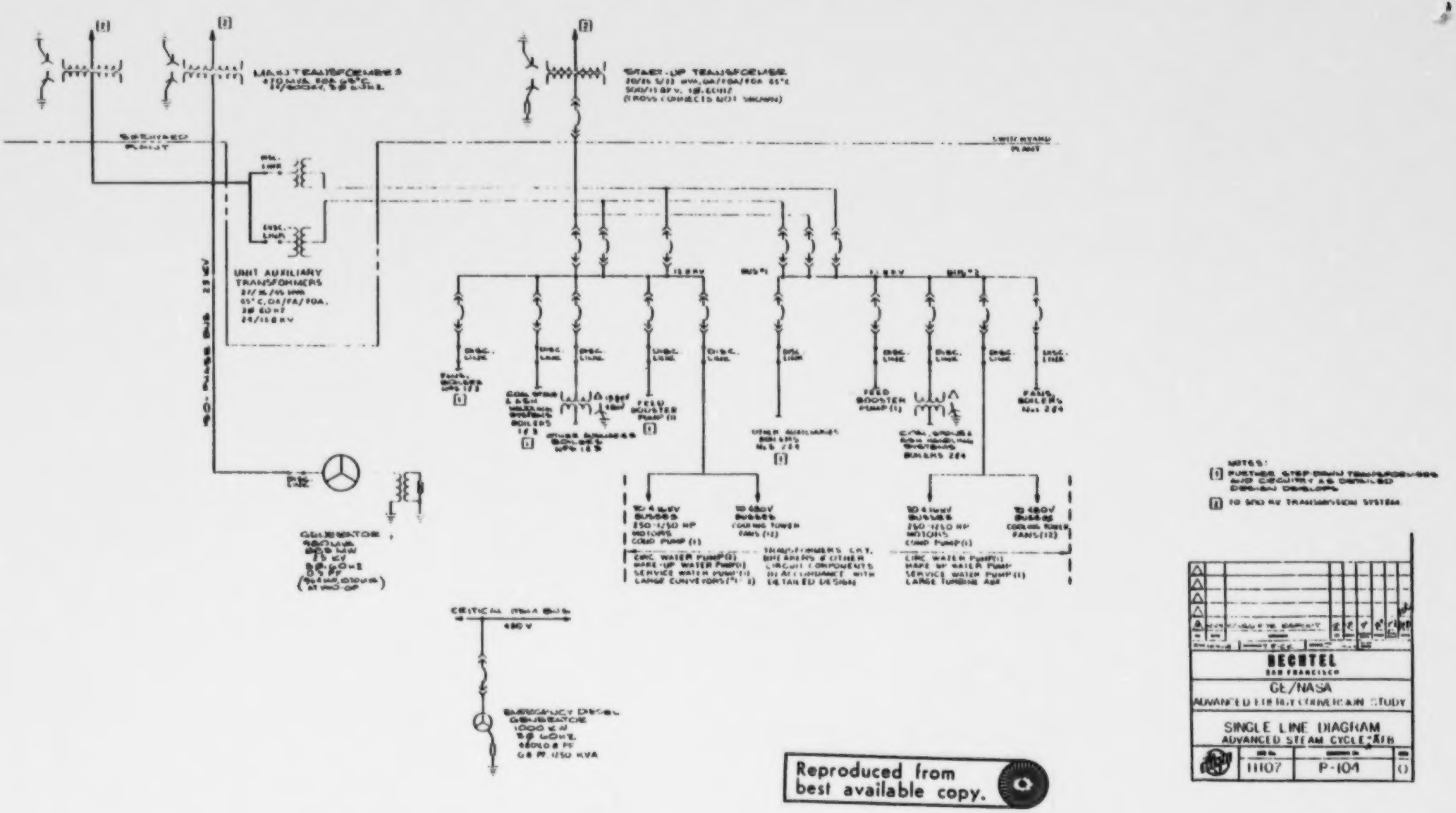
Figure 23. General Arrangement Plan Advanced Steam Cycle — Atmospheric Fluidized Bed (Bechtel)



MAIN TRANSFORMERS
START-UP TRANSFORMER
(CROSS CONNECTS NOT SHOWN)
SWITCHYARD
PLANT
UNIT AUXILIARY TRANSFORMERS
65°C, OA/FA/FOA.
DISC. LINK
13.8 KV
BUS 1
BUS 2
FEED BOOSTER PUMP (1)
OTHER AUXILIARIES BOILERS
FANS BOILERS
TO 4.16 KV BUSSES
250-1250 HP MOTORS
COND PUMP (1)
TO 480V BUSSES
COOLING TOWER FANS (12)
CIRC WATER PUMP(1)
MAKE-UP WATER PUMP(1)
SERVICE WATER PUMP(1)
LARGE CONVEYORS
TRANSFORMERS, CKT. BREAKERS & OTHER CIRCUIT COMPONENTS IN ACCORDANCE WITH DETAILED DESIGN
LARGE TURBINE AUX
GENERATOR
CRITICAL ITEM BUS
480 V
EMERGENCY DIESEL GENERATOR
1000 KW
NOTES:
[1] FURTHER STEP-DOWN TRANSFORMERS AND CIRCUITRY AS DETAILED DESIGN DEVELOPS
[2] TO 500 KV TRANSMISSION SYSTEM
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
SINGLE LINE DIAGRAM
ADVANCED STEAM CYCLE-AFB
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Figure 24 Electrical Diagram for Atmospheric Fluidized Bed System

Electrical Schematic

A single-line diagram showing major electrical equipment is presented in Figure 25. The steam turbine-generator feeds two main transformers at 25 kV, and two unit transformers feeding the 13.8 kV buses. A startup transformer also may feed the 13.8 kV buses. Major electrical loads are indicated as well as the subsidiary bus bars and the emergency diesel generator.

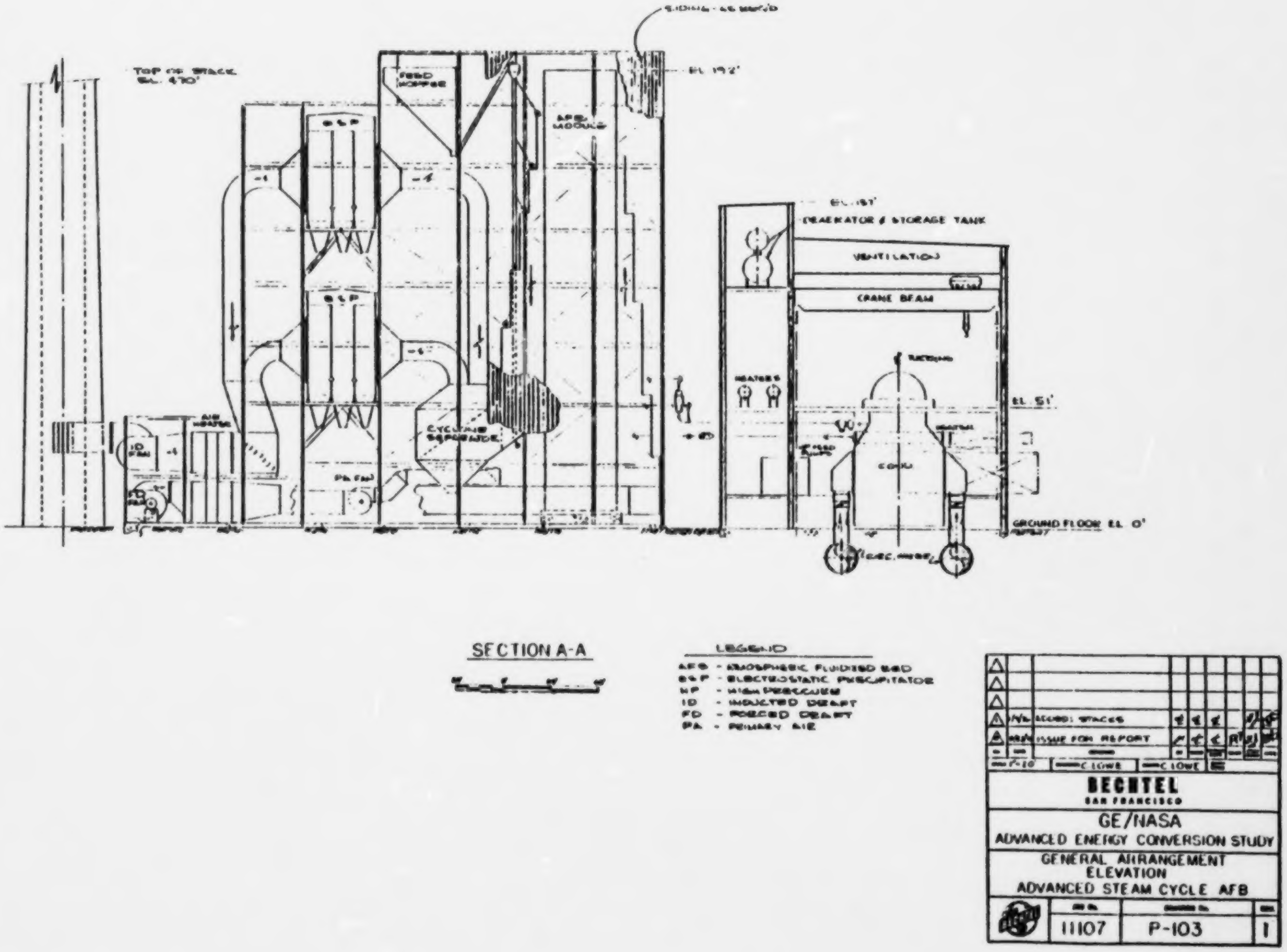
TOP OF STACK EL 470'
SIDING AS REQ'D
EL 192'
EL 151'
DEAERATOR & STORAGE TANK
VENTILATION
CRANE BEAM
HEATERS
COND
EL 51'
GROUND FLOOR EL 0'
ESP
ESP
FEED HOPPER
AFB MODULE
CYCLONE SEPARATOR
AIR HEATER
ID FAN
FD FAN
PA FAN
SECTION A-A
LEGEND
AFB - ATMOSPHERIC FLUIDIZED BED
ESP - ELECTROSTATIC PRECIPITATOR
HP - HIGH PRESSURE
ID - INDUCTED DRAFT
FD - FORCED DRAFT
PA - PRIMARY AIR
ISSUE FOR REPORT
C LOWE
C LOWE
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
GENERAL ARRANGEMENT
ELEVATION
ADVANCED STEAM CYCLE AFB
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Figure 25. General Arrangement Elevation – Advanced Steam Cycle – Atmospheric Fluidized Bed (Bechtel)

5. SYSTEM PERFORMANCE AND COSTS

Performance

System performance concerns boiler efficiency, prime cycle efficiency, and the fraction of gross generation commandeered for auxiliary services. These evaluations are made at the 100 percent operating point and not at the VWO specification point. Table 43 presents the gross generation, the auxiliary power losses, and the net power transmitted from the plant. The auxiliaries are 7.3 percent of the gross generation. Table 44 gives a detailed breakdown for the auxiliary losses. Half of these are attributed to the AFB module services. The FD fan power is four times conventional values as a result of the added flow path resistances for the fluidized bed, the distribution grid plate, and the cyclone separators.

Costs-General

Costs were synthesized from major component costs, BOP material costs, and BOP labor costs. Items made up of numerous smaller components are presented by enumeration of the total cost and unit count for each of the subcomponents. An equipment list for BOP components identifies all major items. A detailed breakdown of BOP labor man-hours and material costs completes identification of all material and construction and installation costs. Thereafter these are combined with major component costs to arrive at total plant costs.

The steam turbine-generator is purchased at a single price of $27 million. In contrast, the steam generator comprises four AFB modules, auxiliary units serving each AFB, conveyor and solids equipment serving pairs of AFB modules, and solids preparation equipment providing three units any two of which can service the entire plant. Equipment lists for the AFB steam generator system are presented as Tables 45, 46, and 47.

Major Component Characteristics

Subsystem costs and weights are presented in Table 48 for the steam turbine-generator and for the AFB modules exclusive of their solids handling equipment and their ESP.

Table 49 presents the characteristics of the AFB module heat exchange and pressure containment parts. The 87.92 percent efficiency represents heat to steam divided by the HHV of all the coal that is fired in the plant. The average heat flux is high compared to conventional boilers. However, the peak heat flux is very much less than peak values for conventional boilers. As a result of these conservative values, the AFB heat exchange surfaces are expected to have a far longer service life than the hottest parts of conventional furnaces and boilers.

Table 43

SYSTEM OUTPUT
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

Total Gross Output (MW_e - 60 Hz AC)	878.66
Total Auxiliary Losses (MW_e - 60 Hz AC) Including Transformer Losses	64.40
Net Powerplant Output (MW_e - 60 Hz AC - 500 kV)	814.26

Table 44

AUXILIARY LOSS BREAKDOWN
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

ITEM	ASSUMPTIONS	NO. OF UNITS	TOTAL MW_e	
Furnace				
SA Fans	24" Δ P, 0.82 EFF	4	0.8	
FD Fans (4)	65" Δ P, 0.82 EFF	4	21.1	
PA Fans (4)	16" Δ P, 0.82 EFF	4	0.5	
ID Fans (4)	16" Δ P, 0.78 EFF	4	5.3	
ESP (8)		8	3.3	
Solids Handling		4	1.4	
				32.5
Turbine	0.33% of Gross kW	1		2.9
Auxiliaries				
Major Pumps				
Service	A/E Estimate	2	0.9	
Booster	600 PSI, 5.44 Million #, 75% x 90%	2	3.4	
Condensate	185 PSI, 4.86 Million #, 70% x 90%	2	1.1	
Circ. Water	Proportion to Cooling Heat Duty	3	4.7	
				10.1
Water Intake	A/E Estimate	2		1.0
Solids Handling	Based on Rates and Lifts	1		1.9
"Hotel" Loads	A/E Estimate 1% of Generation	1		8.8
Cooling Tower Fans	Proportional to Heat Duty	24		2.8
Transformers	0.5% of Gross Generation	4		4.4
			TOTAL AUXILIARY POWER =	64.4

Table 45

SOLIDS HANDLING FOR AFB EQUIPMENT LIST AND COSTS

Subsystems	Cost in 1975 $	Plant Requirement Number	M$
COAL DRYING & CRUSHING			
1 - Dryer System - 189 TPH	$ 910,446		
1 - Coal Crusher & 2 Screens	159,250		
1 - Distribution Box	31,200		
2 - Vibrating Feeders @ 94-1/2 TPH	11,701		
2 - Surge Bins @ 76000 ft^3	59,489		
2 - Bin Activators	20,800		
2 - Weigh Belt Feeders @ 94-1/2 TPH	53,101		
Section Subtotal =	$1,245,987	3	3.74
LIMESTONE DRYING & CRUSHING			
1 - Dryer System @ 43.6 TPH	358,800		
1 - Crusher & 2 Screens	82,550		
1 - Distribution Box	11,128		
2 - Vibrating Feeders @ 24.3 TPH	7,800		
2 - Surge Bins	22,256		
4 - Bin Activators	26,000		
2 - Air Lock Valves	6,501		
2 - Vibrating Feeders	7,800		
2 - Weigh Belt Feeders @ 24.3 TPH	17,906		
Section Subtotal =	540,741	3	1.62
COAL & LIMESTONE BLENDING & FEEDING			
2 - Blenders @ 115 TPH	130,000		
14 - Air Lock Valves	36,983		
14 - Vibrating Feeders	91,002		
56 - Vibrating Tables	657,135		
Section Subtotal =	915,120	3	2.74
SPENT BED MATERIAL COOLING			
2 - Air Lock Valves @ 15 TPH	27,300		
2 - Surge Bins @ Cooler	41,600		
4 - Air Lock Valves @ 30 TPH	67,600		
2 - Solids Cooler & Cyclones	312,000		
Section Subtotal =	448,500	2	0.90
SOLIDS HANDLING CONTROLS			
1 - Control System			
Section Subtotal =	149,058	3	0.45
Subtotal for Solids Handling			9.45

Table 46

HOT GAS AND AIR FOR AFB EQUIPMENT LIST AND COSTS

Subsystems HOT GAS CLEANUP AND AIR SUPPLY	Cost in 1975 $	Plant Requirement Number	Plant Requirement M$
4 - Bed Cyclone Units	$ 392,391		
12 - Cyclone Air Lock Valves	78,000		
4 - Fines Injection Systems	260,000		
2 - CBC Cyclone Units	73,060		
2 - CBC Cyclone Air Lock Valves	25,480		
2 - Surge Bins @ Dust Cooler	40,404		
2 - Coolers for CBC Dust	260,000		
4 - Cooler Air Lock Valves	50,960		
4 - Electrostatic Precipitators	2,406,103		
2 - Air Preheaters	2,392,621		
2 - ID Fans and Motors	881,088		
2 - FD Fans and Motors	964,674		
2 - PA Fans and Motors	90,813		
Section Subtotal =	$7,915,594	2	15.83

Table 47

TOWER COMPONENTS FOR AFB EQUIPMENT LIST AND COSTS

Subsystems Items	M$	Plant Requirement Number	Plant Requirement M$
Heat exchange and pressure parts	5.063		
Injector and air parts of AFB	0.781		
Control system	0.724		
Flues, ducts, insulation, etc.	0.893		
	7.461	4	29.84
Total for modules without solids handling		4	45.67
Total above without electrostatic percipitators		4	40.86

Table 48

MAJOR COMPONENT AND SUBSYSTEM WEIGHTS AND COSTS SUMMARY ADVANCED STEAM-ATMOSPHERIC FLUIDIZED BED

MAJOR COMPONENT OR SUBSYSTEM	WEIGHT (FOB) M LB	COMPONENT OR SUBSYSTEM COSTS (FOB) M$	OUTPUT OR DUTY	COST PER UNIT OUTPUT OR DUTY	COST PER LB
Prime Cycle					
Steam Turbine-Generator	6.5	27.0	878.66 MW_e	30.73$/$kW_e$	4.15$/LB
(Generator Alone)	(0.940)	--	878.66 MW_e		--
AFB Module	3.54	10.2	500.3 MW_{th}	20.39$/$kW_{th}$	2.88$/LB

Table 49

HEAT EXCHANGER CHARACTERISTICS ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

HEAT EXCHANGER	NO. OF UNITS	VESSEL SIZE OR TYPE	OUTPUT OR DUTY PER UNIT MBtu	EFFICIENCY	UNIT SURFACE AREA FT^2	UNIT WEIGHT (FOB) M LB	UNIT COST (FOB) M$	HEAT FLUX AVERAGE Btu/(HR FT^2)
AFB Module	4	76'x33'x178'	1707	87.92%	160726	3.54	5.1*	10620

*Heat exchange surfaces and pressure parts only. An additional $5.1 M is required for other module components for a total of $10.2 M per module (see Table 48).

Equipment List-Balance of Plant

The BOP equipment and its specifications are listed in Table 50. The specifications are based on VWO steam turbine flow rates. In addition, electric motor drives for fans and pumps anticipate a further margin of 10 percent flow, 20 percent pressure rise, and 30 percent power. As a result, the motors are sized for continuous duty at levels well above the 100 percent plant operating point.

Capital Costs-Balance of Plant

Table 51 presents the AE's detailed breakdown of the direct manual field labor in thousands of man-hours, and of BOP material costs in thousands of dollars for each major category of the balance of plant. In using these data, an average hourly field labor rate of $11.75 in mid-1975 dollars converts man-hours to dollars. Where field indirect labor is allocated to individual items rather than the total labor for the job, it will be apportioned as 90 percent of the direct field labor, which is equivalent to $10.58 per hour.

The seven major categories used by the AE relate to the principal field labor skills to be applied. A modified subdivision of costs was made using the following categories:

1. Land improvements and structures
2. Coal handling
3. Prime cycle plant equipment
4. Bottoming cycle (not applicable to AFB plant)
5. Electrical plant and instrumentation

Each item or major category in Table 51 has indicated after its title in parentheses the appropriate second category from the preceding list.

Plant Cost Estimates

The installed costs of major system components are presented in Table 52. Those elements related to heat release--the coal and solids handling equipment, the AFB furnace modules, and the ESPs--represent a total of $100 million. The steam turbine-generator along with its feedwater heaters and pumps is half that amount.

The total plant costs using the AE's categories are presented in Table 53. The home office and fee of 15 percent is applied only to the BOP costs. A contingency of 20 percent of all prior costs is applied to cover expected costs not specifically included in the original estimating process. The total plant cost of $332 million represents $378/kW based on total generation, or $408/kW based on net station output.

Table 50

BALANCE-OF-PLANT EQUIPMENT LIST
ADVANCED STEAM PLANT, ATMOSPHERIC FLUIDIZED BED

EQPT. NO.	SERVICE	DESCRIPTION
C-1	Coal Conveyor Belt	60 in wide, 344 ft long, 3000 tph, 375 hp
C-2	" " "	" " 575 ft " " " 660 hp
C-3	" " "	" " 190 ft " " " 435 hp
C-4	" " "	42 in " 1000 ft " 500 tph, 150 hp
C-5	" " "	" " 610 ft " " " 115 hp
C-6	Limestone Conveyor Belt	60 in " 375 ft " 3000 tph, 95 hp
C-7	" " "	36 in " 1035 ft " 125 tph, 21 hp
C-8	" " "	" " 830 ft " " " 27 hp
C-9	Feed Cascade System:	
	2 Conveyor Belts	24 in " 540 ft " 190 tph
	3 " "	" " 170 ft " " "
	12 " "	" " 30 ft " " "
	18 Bucket Elevators	60 ft average height, 190 tph
	2 Conveyor Belts	18 in wide, 540 ft long, 48 tph
	3 " "	" " 140 ft " " "
	15 " "	" " 30 ft " " "
	15 Bucket Elevators	60 ft average height, 48 tph
	2 Conveyor Belts	36 in wide, 140 ft long, 240 tph
	4 " "	24 in " 300 ft " 119 tph
	4 " "	24 in " 110 ft " " "
	4 Bucket Elevators	200 ft high, 119 tph

Table 50 (page 2 of 4)

EQPT. NO.	SERVICE	DESCRIPTION
C-10	Ash Residue Removal System:	
	2 Conveyor Belts	24 in wide, 600 ft long, 64 tph
	1 " Belt	36 in " 1840 ft " 128 "
	1 " "	" " 420 ft " " "
C-11	Six Vibrating Feeders for Car Unloading	Rating 0-750 tph
C-12	Coal Belt Scale	0-3000 tph, 60 in Belt
C-13	Coal and Limestone Sampling System	0-3000 tph, 60 in Belt
C-14	Coal Lump Crusher (3 req'd)	0-10 tph, 10 in Lumps
C-15	Limestone Lump Crusher (3 req'd)	0-10 tph, 10 in Lumps
C-16	Magnetic Coal Cleaner (3 req'd)	500 tph
C-17	Magnetic Limestone Cleaner (3 req'd)	125 tph
C-18	Coal and Limestone Dust Control System	4-6000 cfm Bag Type Dust Collector
C-19	CO_2 Fire Protection System	Adequate to Service Item C-18 Bag-house
C-20	Vibrating Feeders for Limestone Pile (4 req'd)	0-100 tph
C-21	Vibrating Feeders for Coal Piles (8 req'd)	0-200 tph
C-22	Ash Storage Silos (6 req'd)	Total Volume 2,206,800 ft 80 ft dia x 75 ft high
C-23	Eight Coal Silos	375 ton each
C-24	Two Limestone Silos	325 ton each

Table 50 (page 3 of 4)

EQPT. NO.	SERVICE	DESCRIPTION
		2. Electrical Systems
E-1	Main Transformers (2 req'd)	470 MVA, FOA 65°C, 24/500 kV, 3ϕ, 60 Hz
E-2	Unit Auxiliary Transformers	27/36/45 MVA, 65°C, OA/FA/FOA, 24/13.8 kV, 3ϕ, 60 Hz
E-3	Emergency Diesel Generator	1000 kW, 3ϕ, 60 Hz, 480 V, 0.8 PF
E-4	Start-up Transformer	20/26.5/33 MVA, OA/FA/FOA, 65°C, 500/13.8 kV, 3ϕ, 60 Hz
E-5	Miscellaneous 480 V LCC Transformers (17 req'd)	1680 kVA, OA, 65°C, 13.8 kV/480V/277V, 3ϕ, 60 Hz
E-6	4.16 kV Boiler Auxiliary Transformers (2 req'd)	4000 kVA, OA, 65°C, 13.8/4.16 kV, 3ϕ, 60 Hz
E-7	4.16 kV LCC Transformers (2 req'd)	5500 kVA, OA, 65°C, 13.8/4.16 kV, 3ϕ, 60 Hz
		3. Main Fluid Systems
F-1	Main Condenser	4.05 x 10^5 ft^2 heat exchange surface. Design conditions, 2.3 in Hg, 106°F, 3.58 x 10^6 lb/hr. Two shells; each 25 ft wide, 20 ft high, and 40 ft long with 40,500 1-in tubes: straight-through, single pass design, range of circulating water = 30.7 F.
F-2	Piping:	
	Circulating Water	I.D. = 130 in
	Main Steam	I.D. = 7.5 in, tm = 1.95 in
	Boiler Feedwater	I.D. = 13.0 in, tm = 1.3 in
	Cold Reheat	I.D. = 13.0 in, tm = 0.345 in
	Hot Reheat	I.D. = 16.0 in, tm = 0.18 in

Table 50 (page 4 of 4)

EQPT. NO.	SERVICE	DESCRIPTION
F-3	Feedwater Heaters	

	Shell Press./Temp. psia/°F	Tube Press./Temp. psia/°F	Flow (100%) lb/hr	Heat Transfer Area ft^2
LP #1	5/163	210/158	4.8×10^6	16,900
LP #2	11/195	210/190	4.8×10^6	15,928
LP #3	20/228	210/223	4.8×10^6	16,124
LP #4	67/300	210/295	4.8×10^6	21,706
LP	296/416	1040/416	6.04×10^6	30,251
H.P.	745/510	5700/519	6.04×10^6	30,182
DFT	6.04×10^6 lb/hr, @ 353°F			

F-4	Main Condenser Pumps and Motors (2 req'd)	Vertical Centerline 5050 gpm, 750 hp motor driven 410 ft TDH
F-5	Booster Pumps & Motors (2 req'd)	7,300 gpm, 3,850 hp, 1,510 ft TDH
F-6	Main Boiler Feed Pumps & Turbine Drivers (3 req'd)	4,900 gpm, 12,600 hp, 8,300 ft TDH
F-7	Main Circulating Water Pumps and Motors (3 req'd)	100,000 gpm, 2,120 hp, 75 ft TDH
F-8	Cooling Tower (24 Cells)	250,909 gpm
F-9	Exhaust Stacks (2 req'd)	17 ft I.D., 470 ft high

Table 51 (page 1 of 7)

BALANCE-OF-PLANT ESTIMATE DETAIL
ADVANCED STEAM PLANT, ATMOSPHERIC FLUIDIZED BED

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
1.0	AFB STEAM GENERATORS (3)		
1.1	Steam Generator Erection		
-	Erect only (supply by others): includes heat transfer surface and pressure parts; buckstays; braces and hangers; attached flue and duct; fluid bed components; control equipment and valves; miscellaneous piping and small valves; insulation for above	343	
-	Supply and erect: includes support steel for above; access steel; miscellaneous materials and labor operations	158	3,020
1.2	Steam Generator Auxiliaries		
-	Erect only (supply by others): includes P.A. fans; F.D. fans; I.D. fans; air preheaters; coal and limestone feed tables; pipes and air lock valves	70	100
-	Supply and erect: includes external flue and duct; support steel for ductwork; insulation for external ductwork	198	2,570
1.3	Stack Gas Cleanup:		
-	Erect only (supply by others): includes cyclones and electrostatic precipitators	82	
-	Supply and erect: includes support steel for cyclones and precipitators	14	610
		865	6,300

NOTE: ( ) Indicates NASA categories; see Section 3

Table 51 (page 2 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
2.0	TURBINE GENERATOR (3)		
-	Install only (supply by others): includes 883 MWe steam turbine; generator; exciter; auxiliary equipment; integral steam and auxiliary piping; insulation; miscellaneous labor operations	130	100
3.0	PROCESS MECHANICAL EQUIPMENT (3)		
3.1	Boiler Feedwater Pumps		
-	Supply and install: includes turbine-driven main feedwater pumps and drivers (3 @ $940,000 ea.); feedwater booster pumps and motors (2 @ $125,000 ea.)	10	3,200
3.2	Main Circ. Water Pumps (3)		
-	Supply and install: includes main circ. water pumps and motors (3 @ $250,000 ea.)	3	790
3.3	Other Pumps (3)		
-	Supply and install: includes condensate pumps and motors (2 @ $100,000 ea.); and other pumps and drivers not listed elsewhere	5	670
3.4	Main Condenser (3)		
-	Supply and install: includes shells; tubes; air ejectors	27	2,520
3.5	Heaters, Exchangers, Tanks and Vessels (3)		
-	Supply and install: includes l.p. feedwater heaters (4): i.p. feedwater heater; h.p. feedwater heater; deaerating heater and storage tank; miscellaneous heaters and exchangers; tanks and vessels	7	2,580

Table 51 (page 3 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.6	Stacks and Accessories (3)		
-	Supply and erect: includes concrete stacks and liners; lights and marker painting; hoists and platforms; stack foundations	110	1,700
3.7	Turbine Hall Crane (1)		
-	Supply and erect: includes crane and accessories	3	420
3.8	Coal Handling (2)		
-	Erect only (supply by others): includes coal dryers (3); support and access steel for dryers; coal grinders (3); screens at grinders	22	10
-	Supply and erect: includes railcar dumping equipment; dust collectors; primary crushing equipment; belt scale; sampling station; magnetic cleaners, mobile equipment; conveyors to pile; reclaiming feeders; conveyors to cascade; coal cascade; conveyors and bucket elevators to dryers and grinders; recirculating conveyors at grinders; conveyors to blenders	73	5,700
3.9	Limestone Handling (2)		
-	Erect only (supply by others): includes limestone dryers (3); support and access steel for dryers; limestone grinders (3); screens at grinders; limestone surge bins at AFB modules	11	10
-	Supply and erect: includes magnetic cleaners; conveyor to limestone pile; reclaiming feeders; conveyors to cascade; limestone cascade; conveyors and bucket elevators to dryers and grinders; recirculating conveyors at grinders; conveyors to blenders; pneumatic transport feeders, hoppers, blowers and piping to AFB modules	45	1,960

Table 51 (page 4 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.10	Coal and Limestone Blend Handling (2)		
-	Erect only (supply by others): includes blenders (3); surge bins; bin unloaders and feeders	4	10
-	Supply and erect: includes conveyors and bucket elevators to AFB modules	13	920
3.11	Spent Solids Handling (2)		
-	Erect only (supply by others): includes high temperature vibrating feeders and conveyor to solids cooler; solids cooler	6	10
-	Supply and erect: includes fly ash handling system for precipitators and air preheater; solids cooler accessories and bucket elevator; ash conveyors; ash storage silos (6) with feeders, unloaders and foundations; railcar loading equipment	93	4,480
3.12	Cooling Towers (3)		
-	Supply and erect: includes mechanical draft towers with fans and motors	63	2,680
3.13	Other Mechanical Equipment (3)		
-	Supply and install: includes water treatment and chemical injection; air compressors and auxiliaries; fuel oil ignition and warm-up; screenwell; miscellaneous plant equipment; equipment insulation	30	1,720
		525	29,400

Table 51 (page 5 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
4.0	ELECTRICAL (5)		
4.1	Main Transformers	4	2,030
4.2	Other Transformers and Main Bus	15	1,160
-	includes startup transformer; station service transformers; generator main bus		
4.3	Switchgear and Control Centers	37	3,020
-	includes switchgear and load centers; motor control centers; local control stations; distribution panels, relay and meter boards		
4.4	Other Electrical Equipment	428	2,400
-	includes communications, grounding; cathodic and freeze protection; lighting; preoperational testing		
4.5	Auxiliary Diesel Generator	2	110
-	includes diesel generator, batteries and associated d.c. equipment		
4.6	Conduit, Cable Trays, Wire and Cable	564	3,580
		1,050	12,300
5.0	CIVIL AND STRUCTURAL		
5.1	Concrete Substructures and Foundations (1)	350	2,890
-	includes turbine building substructure; AFB base mats; coal, limestone and ash handling foundations, pits and tunnels; miscellaneous equipment foundations; auxiliary buildings substructures; miscellaneous concrete		

Table 51 (page 6 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
5.2	Superstructures (1)	230	6,540
-	includes turbine building; auxiliary yard buildings		
5.3	Earthwork (1)	135	300
-	includes building excavations; coal, limestone and ash handling excavations; circ. water system excavations; AFB foundation excavations; miscellaneous foundation excavations; dewatering and piling		
5.4	Cooling Tower Basin and Circ. Water System (3)	115	1,800
-	includes circ. water pumps pads, riser and concrete envelope for pipe; cooling tower basin; circ. water pipe; cooling tower miscellaneous steel and fire protection		
5.5	AFB Boiler Enclosures (1)	55	2,170
-	includes structural steel; noninsulated walls and roofing; building services; elevators		
		885	13,700
6.0	PROCESS PIPING AND INSTRUMENTATION		
6.1	Steam and Feedwater Piping (3)	55	2,680
-	includes main steam; extraction steam; hot reheat; cold reheat; feedwater and condensate large piping, valves and fittings		
6.2	Other Large Piping (3)	165	2,670
-	includes auxiliary steam; process water; auxiliary systems		

Table 51 (page 7 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
6.3	Small Piping (3)	85	760
-	includes all piping, valves and fittings of 2-inch diameter and less		
6.4	Hangers and Misc. Labor Operations (3)	245	920
-	includes all hangers and supports; material handling; scaffolding; misc. labor operations		
6.5	Pipe Insulation (3)	40	430
6.6	Instrumentation and Controls (5)	115	2,640
		750	10,100
7.0	YARDWORK AND MISCELLANEOUS (1)		
7.1	Site Preparation and Improvements	38	10
-	includes soil testing; clearing and grubbing; rough grading; finish grading; landscaping		
7.2	Site Utilities	5	50
-	includes storm and sanitary sewers; nonprocess service water		
7.3	Roads and Railroads	27	750
-	includes railroad spur; roads, walks and parking areas		
7.4	Yard Fire Protection, Fences, and Gates	52	600
7.5	Water Treatment Ponds	12	10
-	includes earthwork; compacted-clay lining; offsite pipeline		
7.6	Lab, Machine Shop and Office Equipment	1	280
		135	1,700

Table 52

MAJOR COMPONENT AND SUBSYSTEM CAPITAL COST SUMMARY
ADVANCED STEAM-ATMOSPHERIC FLUIDIZED BED

MAJOR COMPONENT OR SUBSYSTEM	NO. OF UNITS	COST/UNIT (FOB) M$	COMPONENT OR SUBSYSTEM COSTS (FOB) M$	BOP MATERIALS M$	SITE LABOR (DIRECT + INDIRECT) M$	TOTAL INSTALLED COST M$
Fuel Handling & Preparation						
Coal and Solids Handling	3/2	--	9.45	13.10	5.96	28.51
Prime Cycle						
Steam Turbine-Generator	1	27.0	27.00	0.10	2.90	30.00
AFB Furnace Modules	4	10.216	40.86	5.69	17.17	63.72
Electrostatic Precipitators	8	1.203	4.81	0.61	2.14	7.56
Cooling Towers	--	--	--	4.48	3.97	8.45
Pumps, Heat Exchangers, Stacks	--	--	--	11.48	3.62	15.10
Piping, etc.	--	--	--	9.18	13.84	23.02

Table 53

BALANCE OF PLANT CAPITAL COST BREAKDOWN
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

CATEGORIES	COSTS (MILLIONS OF DOLLARS)				
	COMPONENTS	DIRECT LABOR(1)	INDIRECT FIELD(2)	MATERIALS(3)	TOTAL
1.0 Steam Generators	45.68	10.16	9.15	6.30	71.29
2.0 Turbine Generator	27.00	1.53	1.37	0.10	30.00
3.0 Process Mechanical Equipment	9.45	6.17	5.55	29.40	50.57
4.0 Electrical		12.34	11.10	12.30	35.74
5.0 Civil and Structural		10.40	9.36	13.70	33.46
6.0 Process Piping and Instrumentation		8.28	7.46	10.10	25.84
7.0 Yardwork and Miscellaneous		1.59	1.43	1.70	4.72
	82.13	50.47	45.42	73.60	251.62
	BOP Labor, Materials & Indirects (Sum of 1 + 2 + 3)			169.49	
	A/E Home Office & Fee @ 15%				25.42
	Total Plant Cost				277.04
	Contingency @ 20%				55.41
	Total Capital Cost				332.45

A reallocation of costs according to equipment functions is presented in Table 54. Items 1 through 6 include everything in the preceding table. Item 7 adds the value of escalation and interest during the 5.5-year construction time. This item is 55 percent of the prior total. The result is a final plant cost of \$586/kW of total generation or \$632/kW of net station output.

Table 54

PLANT CAPITAL COST ESTIMATE SUMMARY (APPROXIMATE DISTRIBUTION)
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

		MAJOR COMPONENTS M$	BOP MATERIALS M$	SITE LABOR (DIRECT & INDIRECT) M$	TOTAL M$
1.0	Land Improvements & Structures	0	14.0	20.3	34.3
	(Land, Plant Area 108 Acres) (Land, 30-year Dispoal 0 Acres)				
2.0	Coal Handling	9.5	13.1	6.0	28.6
3.0	Prime Cycle Plant Equipment	72.7	31.5	43.6	147.9
	Steam Cycle Atmospheric Fluidized Bed 878.7 MW_e				
4.0	Bottom Cycle not Applicable				
5.0	Electrical Plant & Instrumentation	0.	14.9	26.0	40.9
	Subtotal	82.2	73.5	95.9	251.7
6.0	A-E Service & Contingenty				80.8
7.0	Escalation & Interest during Construction				182.2
				Total M$	514.7
				Plant Output MW_e	814.3
				Total $/kW_e$	632.0

6. NATURAL RESOURCES & ENVIRONMENTAL INTRUSIONS

The natural resources required for this plant are presented in Table 55. Total water withdrawal would be 0.61 gal/kWh, with 0.16/gal/kWh returned from cooling tower blowdown and plant general use after appropriate water treatment. The coal usage relates directly to boiler efficiency, steam turbine cycle efficiency, and the proportion of generated power diverted for auxiliary requirements. The coal usage could be less, and the plant could be made more efficient if the constraint to produce electricity at the least cost was removed.

The environmental intrusions are enumerated in Table 56. The sulfur emissions assumed by GE are comfortably under the current limit, while the nitrogen oxide emissions are less than half the current standard. The major heat rejection is from the cooling tower. The total heat rejected includes the stack loss, loss from hot spent solids, and in-plant thermal energy from motors and other auxiliaries.

The spent solids contain appreciable amounts of unreacted lime as a result of 100 percent excess of limestone feed and the 15 percent of sulfur that is not reacted. There are economic incentives to consider on-site recycling of the spent solids to separate the sulfur and recycle the lime.

Sensitivity to Emissions Targets

The estimated emissions from the atmospheric fluid bed are within existing EPA New Source Performance Standard limitations for conventional coal-fired boilers.

One of the features expected for fluid bed combustion is very low sulfur trioxide generation. Coal end corrosion problems due to sulfur trioxide severely limit conventional furnace design and operation. The AFB power plant and its neighbors should experience reduced probability of acid rain and other aggravations associated with conventional power plants.

Trace Element Emissions

The experimental work needed to determine the levels of trace element emissions from an AFB power plant has not been undertaken to date. Only qualitative comparisons to conventional power plants can be made. The critical factors are main bed temperature of 1550 F, the carbon burnup cell temperature of 2000 F, the absorbency of the porous dry solids of the bed material, and the low solid fly ash emissions level of 0.1 lb/MBtu.

The ash in the Illinois No. 6 coal is 8.9 percent. Therefore, trace elements in the coal that remain with the ash would be found at a concentration in the ash approximately ten times that in the coal, if all the elements remain in the ash. The coal feed rate is 1000 times the particulate emission rate from the stack. The total solids discharged include ash, calcium sulfate, and unreacted lime. The ash is 29 percent of the total solids discharged and is 100 times the stack gas particulate emissions.

Table 55

NATURAL RESOURCE REQUIREMENTS
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

	VALUE
Sorbent, Limestone lb/kWh	0.2272
Coal, lb/kWh	.8839
Water, Total (Gal/kWh)	
Cooling	
Evaporation	0.453
Blowdown	0.14
Plant General Use	0.018
Condensate Makeup	0
Total Land, Acres/100 MW_e	
Main Plant	12.84
Disposal Land	15

Table 56

ENVIRONMENTAL INTRUSION
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

EMISSIONS	LB/MBtu INPUT	LB/kWh OUTPUT
SO_x	1.028*	0.0098
NO_x	0.270**	0.00258
HC		
CO	0.040	0.00038
Particulates	0.099	0.00094

THERMAL POLLUTION	
Heat, Rejected Cooling Towers, Btu/kWh	4794
Heat, Rejected Stack, Btu/kWh	994
Heat, Rejected Total, Btu/kWh	5946

WASTES	LB/kWh	M LB/DAY
Spent Solids Congolomerate	0.292	5.70
42% Calcium Sulfate 31% Ash 24% Unreacted Lime 3% Carbon		
Water Discharge	1.32	25.8

*Based upon available data, EPA believes that limestone would have to be injected into the AFB at a Ca/S ratio of 2.5 to 3.5 to routinely achieve this emission level, rather than the ratio of 2 used in this study.

**Based upon available data, EPA believes that the NO_x emissions level will more typically be in the range of 0.3-0.6 lb/MBtu.

The trace element concentrations in Illinois No. 6 coal are indicated in Table 58. The three categories relate to the manner of their discharge when fired in a slagging cyclone burner in a conventional furnace and boiler. It is projected that in the AFB, the Group I trace elements will not volatilize and will maintain their original proportion to the discharge ash content. This would be a ten-fold concentration in ash when the coal combustibles are removed. The upper limit on stack emission would be at a rate one one-thousandth of their rate of introduction in the coal.

The volatile elements in Group III will likely be volatilized in the AFB bed. Some of these may escape through the stack as gases, but much are likely to be captured or to escape as particulates formed by condensation in the 250 F stack (Hg) or by reaction (HgO, CaF).

The elements in Group II cannot be assigned a distinct trajectory until appropriate tests are made on AFBs. The low and uniform main bed temperature of 1550 F is below the slagging temperature. The carbon burnup cell at 2000 F borders on the slagging temperature range. However, the fluidized beds must operate below slagging temperature to avoid agglomeration of the particles in the bed. It is probable that the least volatile elements like nickel will react as if they were in Group I. Those elements that may partially tend to volatilize will do so in the presence of extensive dry porous granular material which tends to absorb volatiles that are near their dew point temperatures. Since the most porous material with the greatest surface area is the sorbent and the fly ash, a selectively larger concentration should occur in spent sorbent and fly ash. In addition the cooling to 730 F as the gas stream flows over the convection surfaces will result in these volatiles condensing in the fly ash. As a result some elements in Group II may be expected to be found in the particulate emissions in concentrations far greater than their proportion to the ash in the coal.

Table 58

TRACE ELEMENT CONCENTRATIONS IN ILLINOIS NO. 6 COAL*

			Concentration (ppm)
Group I.	Not volatilized during combustion		
		Mn	6-181
		Be	0.5-4
Group II.	Volatilize at slagging temperature but condense on fly ash		
		Pb	4-218
		Sb	0.22-8.9
		Cd	0.1-65
		As	1.7-93
		Ni	8-68
		Cr	4-54
		Zn	10-5350
		Cn	5-44
		V	16-78
Group III.	Volatilize and escape as gases		
		Hg	0.03-1.6
		F	30-167
		Cl	100-5400

*Grouping selected based upon trace elements emission data from a conventional cyclone-fired coal furnace.

7. SUMMARY PERFORMANCE AND COST

Table 59 conveniently summarizes the system performance and cost effects. The plant overall efficiency is lower than the prime cycle thermodynamic efficiency because of the boiler efficiency of 0.8792 and the ratio of net station output to generation of 0.927.

Capital accounts for two-thirds the cost of electricity (COE) for a station capacity factor of 0.65 and fuel cost accounts for under one-third. Historically, these two components of cost have been equal. The current ratios favor low-cost power plants and penalize high efficiency and high capital cost plants.

Table 60 indicates the sensitivity of the COE to changes in the base rates of the factors that dominate electricity generating costs.

Table 59

SUMMARY PERFORMANCE AND COST
ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

ITEM		
Net Power Plant Output (MW_e - 60 Hz - 500 kV)		814.3
Thermodynamic Efficiency (%)		43.9
Power Plant Efficiency (%)		35.8
Overall Energy Efficiency (%)		35.8
Coal Consumption (LB/kWh)		0.884
Total Wastes (LB/kWh)		0.292
Plant Capital Cost ($ Million)		514.6
Plant Capital Cost ($\$/kW_e$)		632.0
Cost of Electricity, Capacity Factor = 0.65		
Capital	(MILLS/kWh)	20.0
Fuel	(MILLS/kWh)	9.5
Maintenance & Operation	(MILLS/kWh)	2.2
Total	(MILLS/kWh)	31.7
Estimated Time of Construction (Years)		5.5
Approximate Date of First Commercial Service		1984 - 1986

Table 60

COST OF ELECTRICITY (COE) SENSITIVITY ADVANCED STEAM CYCLE-ATMOSPHERIC FLUIDIZED BED

	BASE CAPACITY FACTOR 0.65	FUEL COST INCREASE 50%	LABOR COST INCREASE 20%	MATERIALS INCREASE 20%	CAPACITY FACTOR CHANGE 0.5 & 0.8	
COE, Capital	20.0	20.0	21.6	22.4	26.0	16.2
COE, Fuel	9.5	14.3	9.5	9.5	9.5	9.5
COE, O&M	2.2	2.2	2.2	2.2	2.4	2.2
TOTAL COE	31.7	36.5	33.3	34.1	37.9	27.9

D. PRESSURIZED FLUIDIZED BED POWER PLANT

1. INTRODUCTION

The advanced steam cycle power plant with pressurized fluidized beds (PFBs) performs the functions of combustion, steam generation, and sulfur capture in four modular PFBs that use gas turbines to achieve a substantial supercharged pressure level. A simplified cycle schematic, Figure 26, indicates the arrangement of the major equipment. The gas leaving the PFB must be highly filtered before its expansion through the gas turbine. The gas turbine exhaust must be cooled in economizers to utilize its thermal potential fully. This feature substitutes in part, or fully, for the high-pressure feedwater heaters of the steam turbine cycle. The steam turbine and the heat rejection equipment are exactly comparable to units selected for the atmospheric fluidized bed (AFB) plant evaluation.

The system parameters are presented in Table 61. The Illinois No. 6 coal contains 3.9 percent sulfur. Eighty-three percent of the sulfur must be captured to meet the environmental emission limit of 1.2 lb/MBtu of fuel heat release. The capture medium is dolomite fed into each of the six main fluidized beds at twice the rate that would ideally capture all of the sulfur. The 1650 F main bed operating temperature was selected to maximize sulfur capture at 90 percent of that present in the coal.

Unburned carbon is conveyed from the main beds in the fly ash of the gas stream and in the solids tapped from each bed. The 95 percent of the fly ash recovered in the cyclone separators and the tapped solids from the main beds are recycled to a carbon burnup cell (CBC), where a higher temperature of 2000 F and increased excess air of 30 percent produce a substantial burnup of residual combustibles. The net result is both a high combustion efficiency and a high sulfur capture effectiveness.

The pressurizing gas turbine sets provide a supercharge level of 10 for the PFB. The inlet temperature of 1600 F is modest for contemporary gas turbines.

The steam conditions are conventional and correspond to those used for the AFB. The steam cycle has a low final feedwater temperature of 254 F to match the economizer outlet gas temperature of 300 F. Only three feedwater heaters are used.

The net power from the plant would be 904 MW representing 39.2 percent of the higher heating value (HHV) of the coal fired. The steam turbine produces 78 percent of the power and the four gas turbines 22 percent.

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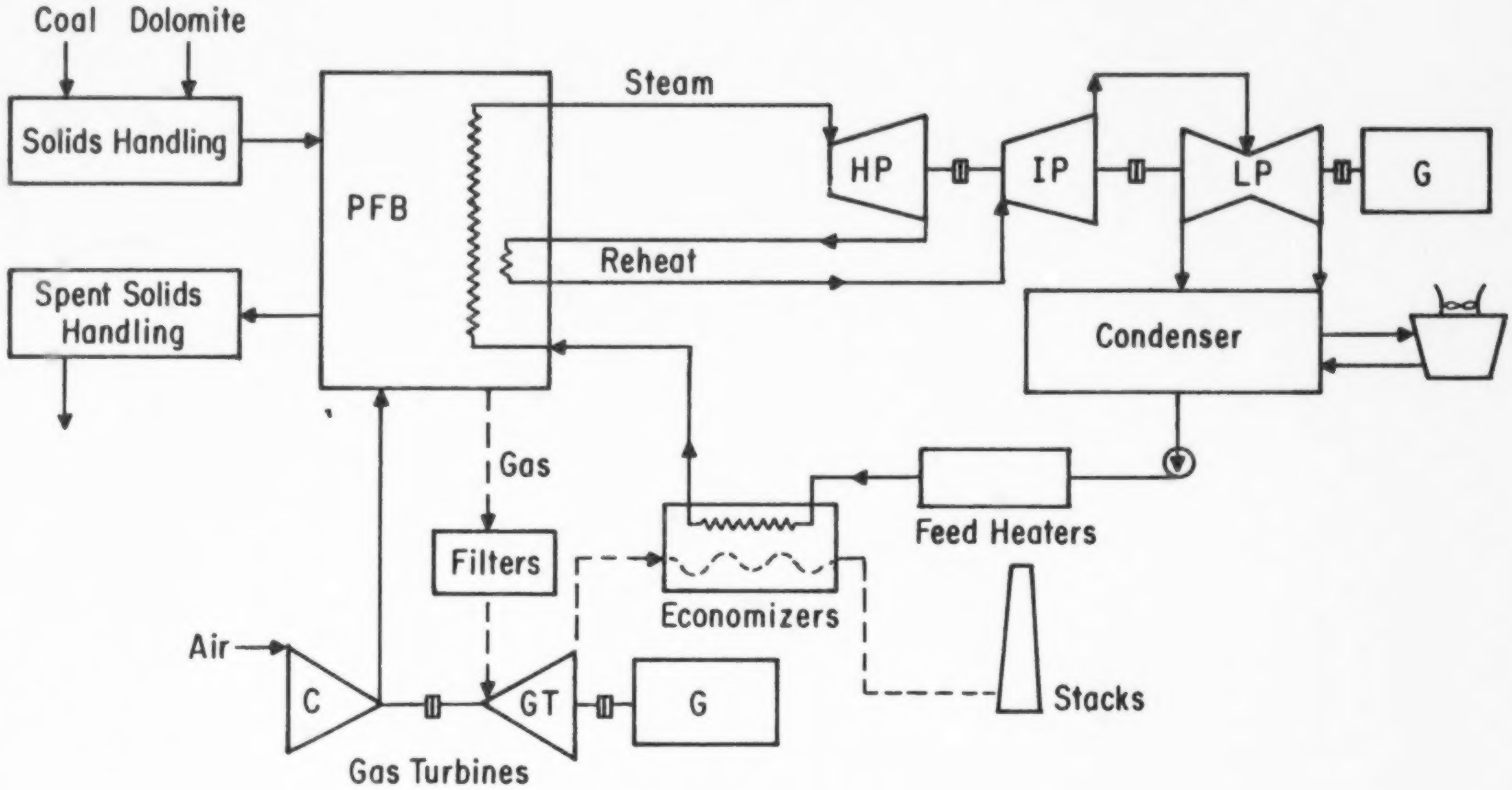

Coal
Dolomite
Solids Handling
Spent Solids Handling
PFB
Steam
Reheat
HP
IP
LP
G
Condenser
Gas
Filters
Economizers
Feed Heaters
Stacks
Air
C
GT
G
Gas Turbines

Figure 26. Simplified Schematic Diagram for Advanced Steam Cycle—Pressurized Fluidized Bed

Table 61

SYSTEM PARAMETERS
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED

PARAMETER	VALUE OR DESCRIPTION
FUEL	
ILLINOIS NO. 6 COAL	10788 Btu/LB HIGHER HEATING VALUE $1/MILLION Btu
DOLOMITE	SULFUR CAPTURE MEDIUM 0.46 LB/LB COAL
FURNACE	
PRESSURIZED FLUIDIZED BED - COMBUSTOR AND STEAM GENERATORS (4 MODULES)	
MAIN BEDS (6 PER MODULE)	1650 F. COAL AND DOLOMITE, 20% XS AIR
CARBON BURNUP BED (1 PER MODULE)	2000 F. FLY ASH AND SOLIDS DRAIN, 30% XS AIR
GAS TURBINE	1600 F INLET, 10 PRESSURE RATIO
EXHAUST GAS	ECONOMIZER HEAT TO FEEDWATER
PRIME CYCLE - STEAM PLANT	
WORKING FLUID	STEAM
TURBINE INLET	3500 psi, 1000 F
REHEAT	676 psi, 1000 F
CONDENSER	2.3" Hga, 106 F
FINAL FEEDWATER	4378 psi, 254 F
HEAT EXCHANGERS	
GAS TURBINE EXHAUST	GAS 850 F IN/300 F OUT
ECONOMIZER	WATER 533 F OUT/254 F IN
HEAT REJECTION	
WET MECHANICAL DRAFT COOLING TOWERS	22 CELLS
STACK GAS TEMPERATURE	300 F

2. CYCLE DESCRIPTION

A more detailed plant schematic is presented in Figure 27. State points and stream flows are shown in which the enthalpy values are referenced to 32 F water for steam and water, and to an 80 F zero references for air, combustion gases, and solids. This power plant uses four PFB boiler modules to convert the energy from high sulfur coal into steam for a conventional 3515 psia/1000 F/1000 F steam turbine cycle with single reheat of steam. One tandem compound four-flow steam turbine-generator produces 738.63 MW gross electric energy output. Incorporated with each PFB boiler is an open cycle gas turbine that supplies the air from its compressor to the PFB boiler. This pressurized air stream fluidizes the bed and reacts with injected coal to develop the heat for steam generation. The resulting hot gases return to the turbine for expansion to atmospheric pressure. This expansion in the turbine develops sufficient shaft power to drive the compressor and an electric power generator that also delivers 51.25 MW gross electric energy output. Thus, the combined plant output from the steam turbine-generator and four gas turbine-generators is 943.63 MW gross.

The regenerative feedwater heating cycle has two low-pressure feedwater heaters, a deaerator, and a high-pressure feedwater economizer that extracts heat from the gas turbine exhaust gases. A portion of the exhaust steam from the intermediate pressure turbine is extracted for powering condensing steam turbines that drive the boiler feedpumps. All other major pumps are driven with electric motors.

The sulfur present in the coal combines with dolomite injected into the PFB boilers with the coal to form calcium sulfate, which is removed along with coal ash and dolomite residue from the PFB boilers. Hot gases from the PFB boilers are cleaned in cyclone separators followed by granular bed filters. After the particulates in the flue gas are filtered and the energy from the hot gases recovered in the gas turbine and the economizer, the flue gas at 300 F is discharged to the atmosphere. The clean flue gas will meet the national standards for emissions from new coal-fired power plants.

Pressurized Fluidized Beds

The feedwater to each PFB would be at 533 F after being heated in the gas turbine exhaust economizer. Within the PFB unit this water is heated to steam turbine throttle conditions of 3500 psig, 1000 F. After expansion in the high pressure turbine, the steam returns to the PFB at 767 psia, 604 F to be reheated to 1000 F. There are six main beds and one carbon burnup cell in each PFB pressure container or module. The heat exchange surfaces are mainly submerged in the fluidized bed and its containing waterwalls. Convection surfaces are not used since the intent is to provide a high gas turbine inlet temperature of 1600 F in conjunction with high temperatures of 1650 F in the main fluidized beds. The CBC operates at 2000 F, using recycled solids from the main bed taps and from the cyclone separators.

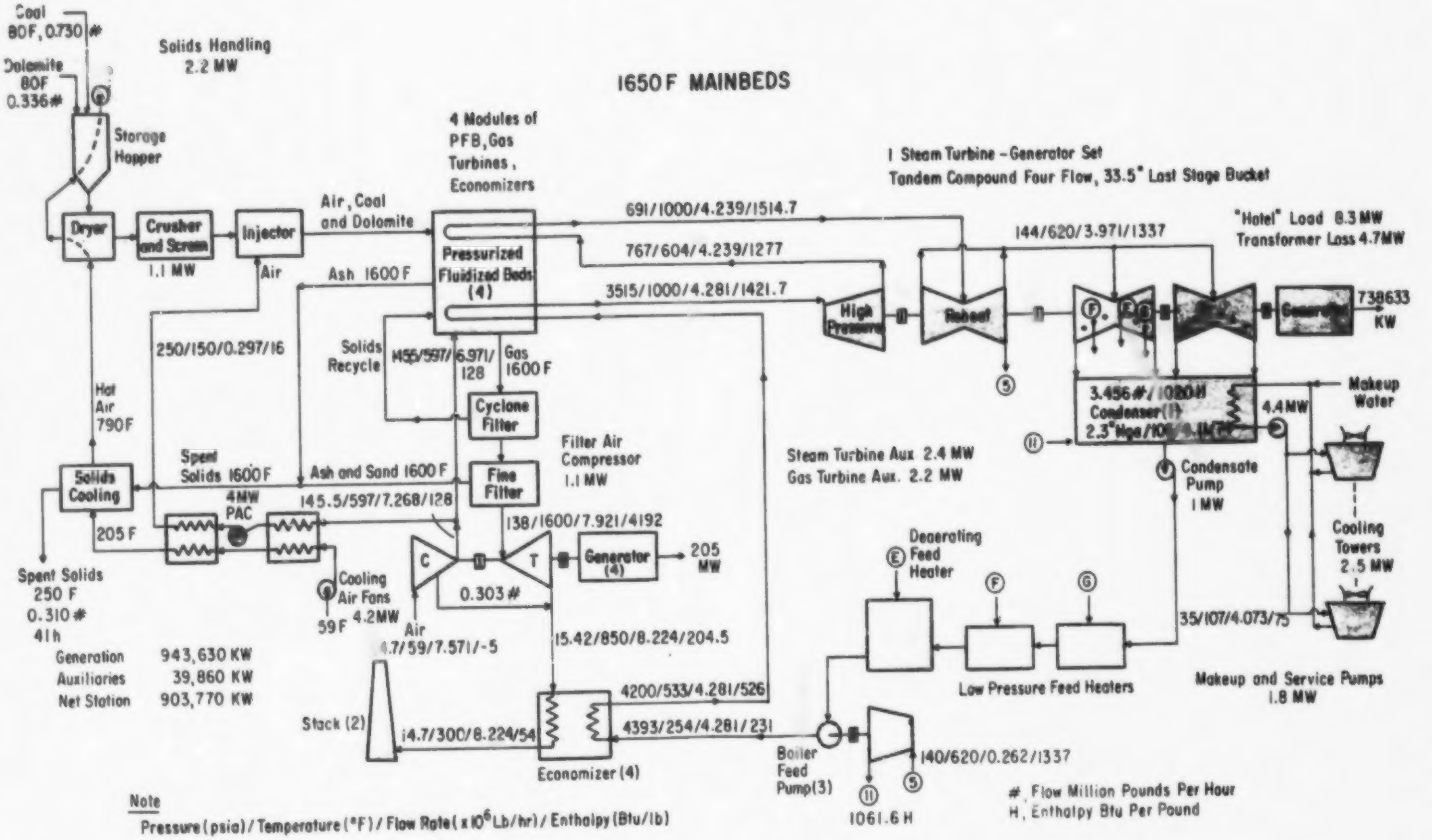

1650 F MAINBEDS
Coal 80F, 0.730 #
Dolomite 80F 0.336 #
Solids Handling 2.2 MW
Storage Hopper
Dryer
Crusher and Screen
1.1 MW
Injector
Air
Air, Coal and Dolomite
4 Modules of PFB, Gas Turbines, Economizers
Pressurized Fluidized Beds (4)
Ash 1600 F
250/150/0.297/16
Solids Recycle
1455/597/6.971/128
Gas 1600 F
Cyclone Filter
Fine Filter
Filter Air Compressor 1.1 MW
Hot Air 790F
Solids Cooling
Spent Solids 1600 F
Ash and Sand 1600 F
4MW PAC
145.5/597/7.268/128
205 F
138/1600/7.921/4192
C
T
Generator (4)
205 MW
0.303 #
Cooling Air Fans 4.2MW
59 F
Air
14.7/59/7.571/-5
15.42/850/8.224/204.5
Spent Solids 250 F 0.310 # 41h
Generation 943,630 KW
Auxiliaries 39,860 KW
Net Station 903,770 KW
Stack (2)
14.7/300/8.224/54
Economizer (4)
4200/533/4.281/526
4393/254/4.281/231
691/1000/4.239/1514.7
767/604/4.239/1277
3515/1000/4.281/1421.7
High Pressure
Reheat
1 Steam Turbine - Generator Set
Tandem Compound Four Flow, 33.5" Last Stage Bucket
144/620/3.971/1337
"Hotel" Load 8.3 MW
Transformer Loss 4.7MW
738633 KW
5
3.456 # / 1020 H
Condenser (1)
11
4.4 MW
Makeup Water
Condensate Pump 1 MW
Cooling Towers 2.5 MW
Steam Turbine Aux 2.4 MW
Gas Turbine Aux. 2.2 MW
Deaerating Feed Heater
E
F
G
35/107/4.073/75
Low Pressure Feed Heaters
Makeup and Service Pumps 1.8 MW
Boiler Feed Pump (3)
140/620/0.262/1337
1061.6 H
#, Flow Million Pounds Per Hour
H, Enthalpy Btu Per Pound
Note
Pressure (psia) / Temperature (°F) / Flow Rate (x10^6 Lb/hr) / Enthalpy (Btu/lb)

Figure 27. Schematic Diagram of Advanced Steam Cycle - Pressurized Fluidized Bed (1650 F Main Beds)

Gas Turbine Air Supply

Each gas turbine is of a basic conventional design using a pressure ratio of 10. A fraction of the delivered air from the compressor is pressurized an additional 100 psi in the Petrocarb air compressor (PAC) to convey the coal and dolomite into the main beds through the injection feed pipes. The cooling for the PAC heats air for coal and dolomite drying along with heat reclaimed from the spent solids cooler. The bulk of the air supply goes directly to the PFB unit. In addition 22 MBtu/hr are added to boiler feedwater in the portion of the PAC cooler serving as an economizer.

The gas from the PFB contains fly ash particulates. Cyclone separators remove 95 percent of this solid burden. Then the fine filters remove the rest to the level of cleanliness required for gas turbine durability. The fine filters are granular bed units that are periodically backflushed with fluidizing air to purge them of accumulated solids.

The inlet flue gas to the turbine is at 1600 F and 138 psia, a loss of 7.5 psi relative to the compressor discharge. The 850 F turbine exhaust serves a heat recovery economizer in the steam cycle, producing 300 F stack gas.

Spent Solids System

The CBC solids tap and the cyclone filter tap for the CBC and the solids and carryover sand from the granular fine filter purge are accumulated in the solids cooler. Their temperature is reduced to 250 F while producing 790 F air for drying feedstock. These spent solids comprise 42 percent ash, 26 percent calcium sulfate, 13 percent unreacted lime, 16 percent magnesium oxide and 4 percent unburned carbon.

Coal and Dolomite Systems

Hot air for drying is drawn through the active dryers and then the feed storage silos. Coal and dolomite are crushed to size and then pressurized for distribution and injection using the Petrocarb high pressure solids injection system. Recycled fly ash and tapped solids are fed to the CBC by a combined gravity and air assisted transport.

Overview

The overall system for using PFBs achieves sulfur capture during combustion, and a high combustion efficiency by recycle of air-borne solids containing unburned carbon. The four self-contained modules of PFB and gas turbine assure that only one-quarter of capacity would be lost during outages of a single module. The plant aggregates 944 MW of generation, of which 22 percent is from gas turbines. The net station output would be 904 MW.

3. MAJOR CYCLE COMPONENTS

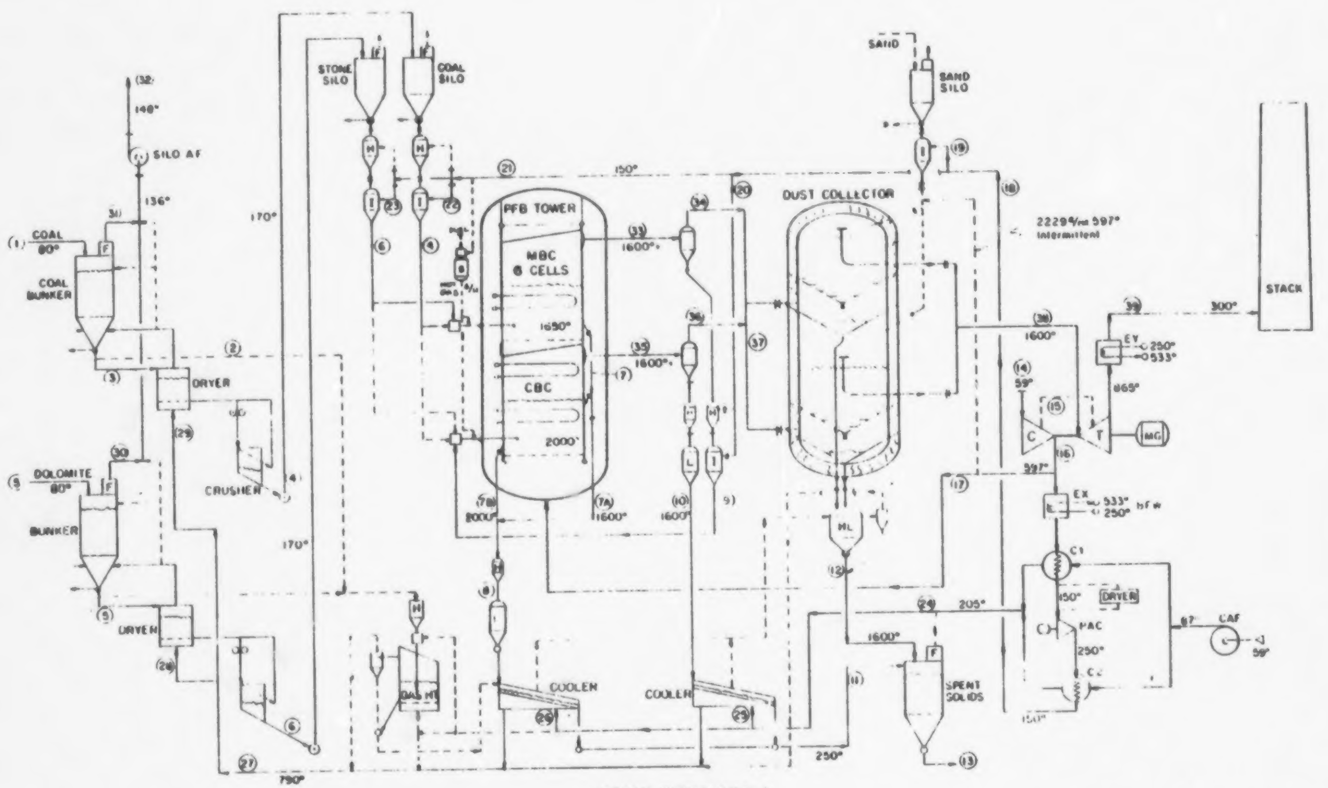
The usual specification for steam power plants add a 5 percent margin of flow and capacity to every major component. Such an approach would upset the close integration of the many components of a PFB system. To assure perfect matching of all pieces of the system, the fuel and air and heat absorption of the PFB were fixed as the common parameters for the gas turbine, compressor, PFB module, and steam turbine heat supply. The physical size limitation on the PFB tower closely matched the airflow rate for current gas turbines. From these considerations the air for combustion, fuel for combustion, dolomite rate, and gas flow to the gas turbine were fixed. The coal rate so established was 1.4 percent greater than the coal rate for the AFB plant at its 100-percent rating point.

The design and performance details of the PFB modules, the pressurizing gas turbine and economizer, and the steam turbine-generator are considered in this section on major components. All remaining equipment would be specified and supplied as balance-of-plant (BOP) materials. Equipment lists for all items are provided in a subsequent section, "System Performance and Cost."

Heat Input System-PFB

The PFB heat input major components comprise the PFB tower module, the solids handling for coal, dolomite, and spent solids, the hot gas filtering system, the fuel and dolomite injection systems, and the gas turbine air supply with its exhaust heat economizer. Conceptually the functions are similar to those described for the AFB. The solids handling requires lock hoppers to pressurize the feed solids and to depressurize the spent solids. The hot gas filtration requires two stages of cyclone filters followed by the fine granular bed filter. The PFB beds operate in an alkaline environment at low-temperature levels relative to conventional boilers and at a very low sulfuric acid dewpoint. The ash products are soft and dry and will not adhere to heat transfer surfaces. As a result of these favorable conditions, no coal ash corrosion problems within the PFB beds are expected. Emissions of sulfur dioxide will be under the current limits as a result of the 90 percent sulfur capture in the main beds. Nitrogen oxide emissions will be one-third the current limits; practically all nitrogen oxides result from fuel-bound nitrogen since the low bed temperatures form very little thermal NO_x. The effect on gas turbine nozzle and bucket life will be an important determination for pilot and demonstration units. The flow of materials and the temperature levels throughout one PFB module are presented in the process flow schematic, Figure 28. The interior arrangement of the PFB tower module is shown in Figure 29. The identity of each heat exchange element is shown in that figure, and the detailed heat exchange and temperatures appear on the heat absorption layout in Figure 30. Table 62 presents the resulting surface requirements and selected tubing to satisfy the requirements for each PFB module.

The heat exchange surfaces selected tend to take advantage of the greatest heat transfer temperature differences and thus minimize surface area



COAL
80°
COAL BUNKER
SILO AF
140°
136°
DOLOMITE
80°
BUNKER
DRYER
CRUSHER
DRYER
170°
170°
790°
STONE SILO
COAL SILO
PFB TOWER
MBC
6 CELLS
1650°
CBC
2000°
2000°
1600°
150°
1600°
1600°
1600°
COOLER
COOLER
GAS HT
DUST COLLECTOR
SAND
SAND SILO
2229#/hr 597°
intermittent
STACK
300°
1600°
59°
597°
865°
EY
250°
533°
C
T
MG
EX
533°
250°
BFW
C1
150°
DRYER
PAC
250°
C2
150°
CAF
59°
ML
SPENT SOLIDS
1600°
205°
250°

STREAM FLOWS (lb/hr)

	1	2	3	4	5	6	7	7A	7B	8	9	10	11	12	13	14	15	16	17	18	19	20
COAL	142462		182462	182391																		
STONE					83983	82332																
SOLIDS							34154	28462	5692	34154	47574	39846	74,000	3366	77366							
GAS											11893											
AIR																1,888,924	71,924	1,817,000	1,742,824	74175	1101	11893
TOTAL		START-UP ONLY									59467											

	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
																		1101	73,025
AIR	61181	20583	40598	169772	80416	89359	169772	21575	148187	23206	166268	191474	1,878,765	1,878,765	104,293	104,293	1,983,058	1,983,058	1,983,058
GAS													50078	2504	[illegible]	1059	3563	197	197
SOLIDS																			
TOTAL													1,928,843	1,881,269	145,199	105,352	1,986,621	1,984,356	2,056,280

----- STREAMS NORMALLY SMALL · NOT CONSIDERED

Figure 28. Process Flow Schematic (Foster Wheeler)

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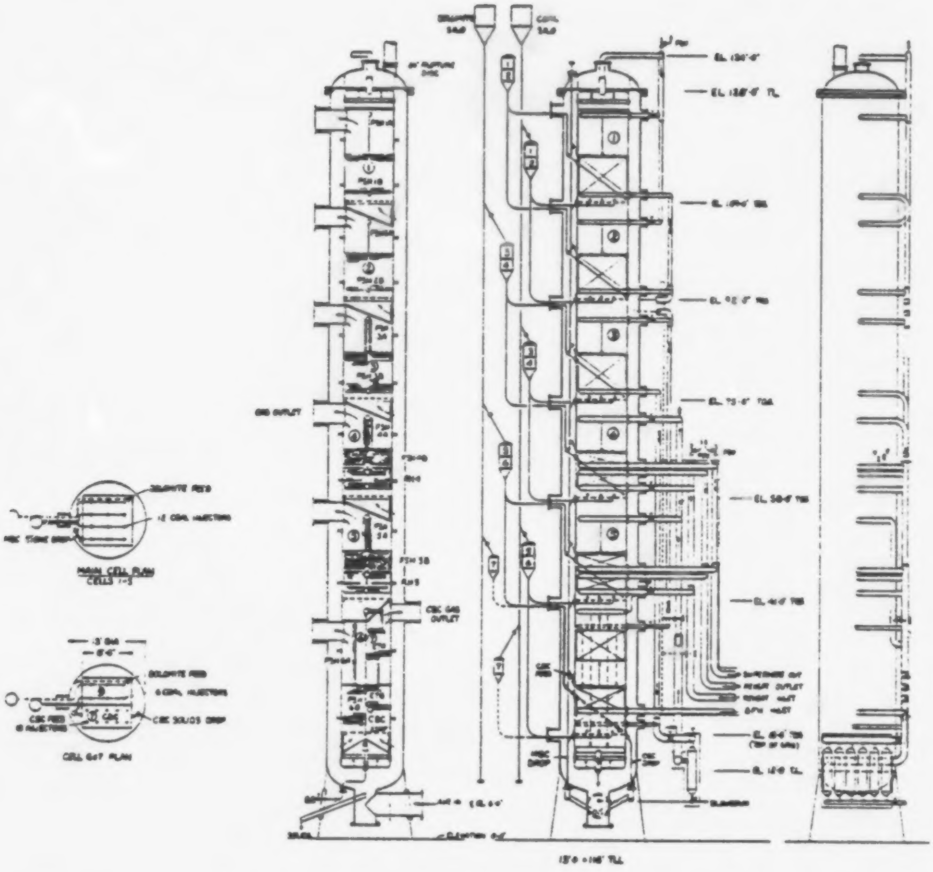

DOLOMITE FEED
COAL INJECTORS
MAIN CELL PLAN
CELLS 1-5
DOLOMITE FEED
COAL INJECTORS
CBC FEED
INJECTORS
CBC SOLIDS DROP
CELL 6&7 PLAN
CBC GAS OUTLET
CBC
EL 138'-0" TL
REHEAT OUTLET
REHEAT INLET
EL 12'-0" TL

Figure 29. Advanced Steam Cycle — Pressurized Fluidized Bed — Boiler (Foster Wheeler)

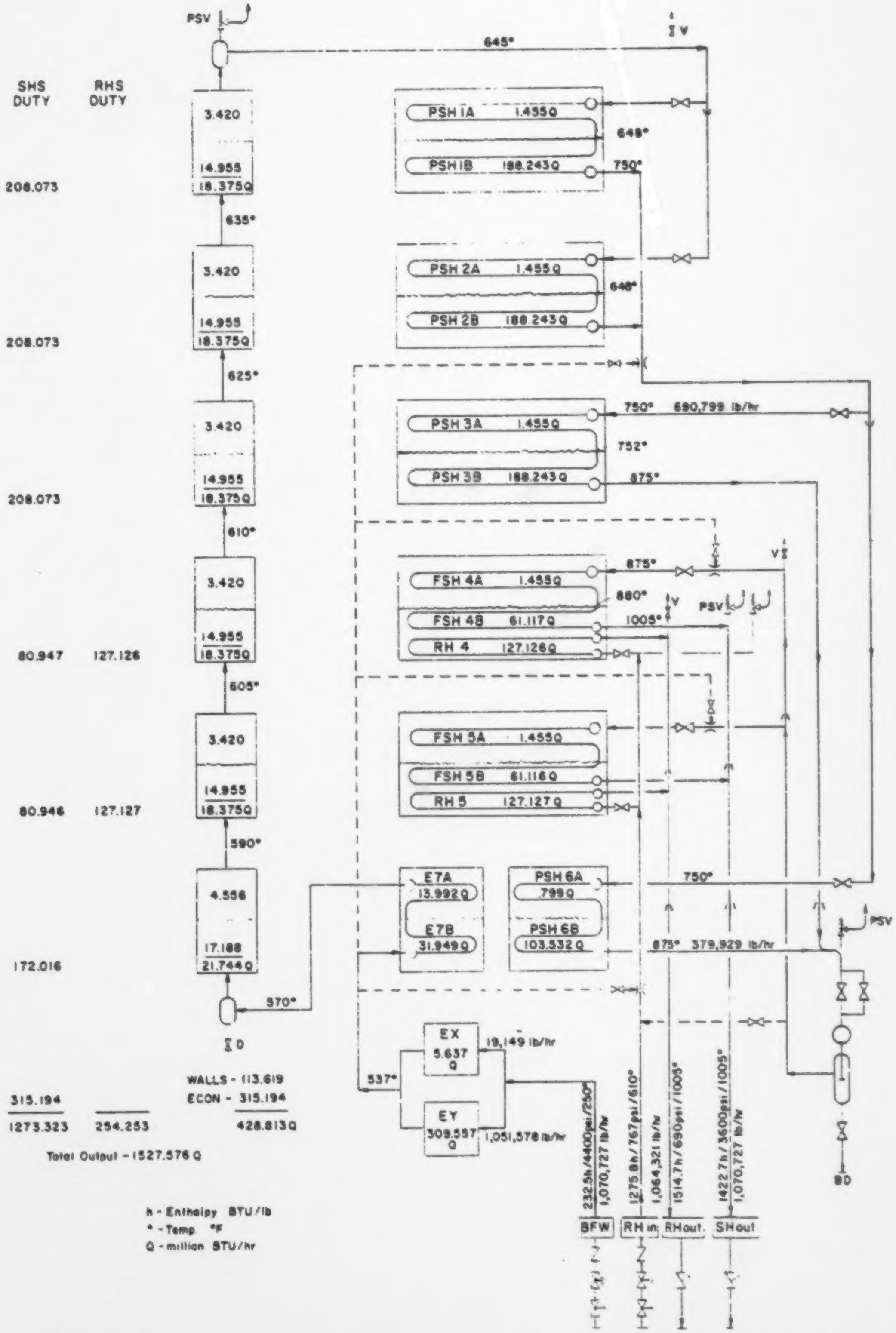

PSV
645°
V
SHS DUTY
RHS DUTY
3.420
14.955
18.375Q
208.073
635°
PSH 1A 1.455Q
648°
PSH 1B 188.243Q
750°
3.420
14.955
18.375Q
208.073
625°
PSH 2A 1.455Q
648°
PSH 2B 188.243Q
3.420
14.955
18.375Q
208.073
610°
PSH 3A 1.455Q
750° 690,799 lb/hr
752°
PSH 3B 188.243Q
875°
3.420
14.955
18.375Q
80.947
127.126
605°
FSH 4A 1.455Q
875°
V
880°
FSH 4B 61.117Q
1005°
V
PSV
RH 4 127.126Q
3.420
14.955
18.375Q
80.946
127.127
590°
FSH 5A 1.455Q
FSH 5B 61.116Q
RH 5 127.127Q
4.556
17.188
21.744Q
172.016
E7A
13.992Q
E7B
31.949Q
PSH 6A
.799Q
PSH 6B
103.532Q
750°
875° 379,929 lb/hr
PSV
570°
D
EX
5.637
Q
19,149 lb/hr
537°
EY
309.557
Q
1,051,578 lb/hr
WALLS - 113.619
ECON - 315.194
315.194
1273.323
254.253
428.813Q
Total Output - 1527.576 Q
232.5h/4400psi/250°
1,070,727 lb/hr
1275.8h/767psi/610°
1,064,321 lb/hr
1514.7h/690psi/1005°
1422.7h/3600psi/1005°
1,070,727 lb/hr
BFW
RH in
RHout
SHout
BD
h - Enthalpy BTU/lb
° - Temp °F
Q - million BTU/hr

Figure 30. Advanced Steam – PFB Circuit Absorption Diagram

Table 62

PFB MODULE HEAT EXCHANGE SURFACE DETAILS

BANK SERVICE	Q_o MBtu/hr	S_o ft^2	Ø_o(in)	N_s	S_t(in)	S_L(in)	BC(in)	NR	L/L	Loops	$\text{Ø}_1/\text{Ø}_2$(in/in)
E7A	13.992	617	1-3/4	22	4-1/2	2-1/4	71"	16	2	8	10-10/-
E7B	31.949	463	1-3/4	22	4-1/2	2-1/4	53"	12	2	6	-/10-10
WW	113.619	4450	1-1/4" + Fin	270	1-1/2	Fin	-	270	270	1/2	10-5/5-10 8 F+R
PSH1,2A	1.455	95	1-1/4"	68	3	1-5/8	2-7/8"	1/2	1	1/4	8-8/-
PSH1,2B	188.243	4539	1-1/2"	68	3	1-5/8	77-5/8"	24	1	12*	-/8-8
PSH3A	1.455	95	1-1/4"	68	3	1-5/8	9-3/8	1/2	3	1/4	8-8/-
PSH3B	188.243	4540	1-1/4"	68	3	1-5/8	77-5/8	24	3	4*	-/10-10
PSH6A	.799	52	1-1/4"	68	3	1-5/8	9-3/8	1/2	3	1/4	6-6/-
PSH6B	103.532	2497	1-1/4"	68	3	1-5/8	77-5/8	24	3	4	-/8-8
FSH4,5A	1.455	95	1-1/4"	68	3	1-5/8	15-7/8"	1/2	5	1/4	10-10/-
FSH4,5B	61.117	1892	1-1/4"	68	3	1-5/8	32-1/8"	10	5	1*	-/10-10
RH4,5	127.127	3026	1-1/4"	68	3	1-5/8	51-5/8"	16	2	4*	10-10/12-12
EX	5.637	5220	1	44	1-1/2	3 sq.	64"	22	1	-	3/3
EY	309.557	179326	2" Fin	68	4	6	81-1/2	14	1	7	10/10

Size	W	x D	x H
EX	8'Ø	x 24' Lg	x -
EY	23'	x 38'	x 10'
Beds 1-5	8'-6"	x 8'-6"	x 8'
6	4'-8"	x 8'-6"	x 8'
7	3'10"	x 8'-6"	x 6'

*Loops are half length with central outlet headers.

Q_o - Duty - mm Btu/hr
S_o - Surface - ft^2
Ø_o - Tube O.D. (in.)
N_s - No. Sections
S_t - Side spacing (in.)
S_L - Back spacing (in.)
BC - Bundle clearance (in.)
NR - No. runs/section
L/L - loop in loop
$\text{Ø}_1/\text{Ø}_2$ - in/out header dia. (in.)

requirements. Staggered in-bed tube pitches were selected with spacing that promotes a good uniformity of bed fluidization.

PFB Gas Turbine and Heat Balance

Each PFB unit has a gas turbine with an exhaust economizer. Performance specifications are presented in Figure 31 and Table 63 for the units serving the 1650 F PFBs. The state points and heat duties integrate exactly with the flow rates and heat duties of Figure 28 and of the steam turbine heat balance Figure 32. The basic fixed parameters were the air for combustion at state 2 of Figure 30 and the coal rate per module of 182, 462 lb/hr.

The gas turbine compressor has 17 stages and the turbine has 3. The design, except for modification to the normal combustor section, is characteristic of current 3600-rpm designs. It is anticipated that blade coatings and claddings may be required to counter any chemical or particulate attack on the nozzles or buckets.

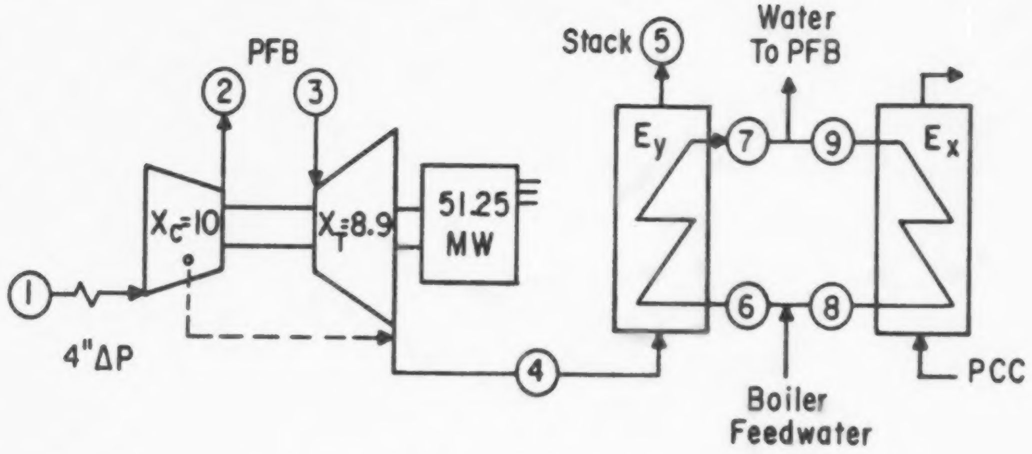
Prime Cycle

The major component for the prime cycle is the steam turbine-generator. The selected unit was a General Electric tandem compound turbine with four-flow exhaust using 33.5-in. last-stage buckets. The 3500 psig/1000 F high-pressure turbine and 691 psig/1000 F reheat turbines are comparable to units supplied for the AFB prime cycle. The heat balance of Figure 31 was based on exactly matching the 6.105 MBtu/hr heat to steam cycle produced by the four PFBs, their gas turbine economizers, and their Petrocarb compressor economizers. The high-pressure feedwater heaters have been eliminated since feedwater at 533.3 F will be produced by the economizers with a pinchpoint temperature of 46.5 F. The elimination of high-pressure steam feed heaters in the steam cycle reduces its cycle efficiency to 41.3 percent. The heat rejection system is identical to that presented in Table 65 except that flows, power, and number of cells are porportional to condenser heat duty. (See table 64.)

Materials Considerations

Concern with the pressurized fluidized bed with a bed temperature of 1650 centers mainly on the problems created by hot corrosion. Apart from the use of some higher temperature alloys, the problems are qualitatively similar to those for the AFBs. Critical temperature ranges will depend on the alloy selected and the nature of the chemicals formed, which in turn will depend on the coal composition.

There may be a severe hot corrosion problem in the pressurizing gas turbine and also erosion and fouling of critical components. The problem of hot corrosion in the turbine can be essentially rationalized in terms of the contaminant level in the gas stream. The limits for materials in current use are well documented. If these limits cannot be maintained through hot gas



Station	1	2	3*	4	5	6	7	8	9
Gas flow, lb/hr	1888924	1817000	1984159	2056083	2056083	0	0	0	0
Water flow, lb/hr	0	0	0	0	0	105131	105131	19145	19145
Pressure, psia	14.7	145.5	138.0	15.42	14.7	4393	4200	4393	4200
Temperature, °F	59	597	1600	850	300	253.5	533.3	253.5	523.5
Enthalpy, Btu/lb	-5	128	426.4	204.5	.54	231.2	525.65	231.2	525.65
Heat duty, MBtu/hr		1211.13		309.56		309.56		5.64	
Unit		PFB		Ey		Ey		Ex	

*Gas turbine limits for gas stream 3

Constituent	Concentration ppm by Weight
Sodium and potassium	Under 0.02
Lead	Under 0.02
Vanadium	Under 0.01
Calcium	Under 0.04
Trace - others	Under 0.01
Solids except HC's, total	1
Solids over 10 microns	0.01
Solids over 13 microns	0.001

Figure 31. 1650 F Pressurized Fluidized Bed Module Gas Turbine, Economizer E_Y, and Petrocarb Compressor Cooler Economizer E_X

Table 63

GAS TURBINE SPECIFICATIONS FOR PRESSURIZED FLUIDIZED BEDS

Ambient - ISO 59F, 14.7 psia

Compressor - Stages 17

Pressure ratio 10:1

Inlet pressure drop 4" H_2O

Combustor pressure drop - 5%

Turbine - Stages 3

Inlet temperature 1600°, 1700°

Turbine inlet Mach number 1.0

Turbine nozzle flow coefficient 1.0

Diffuser inlet Mach number 0.5

Diffuser exit Mach number 0.05

Diffuser pressure loss coefficient 0.46

Exhaust pressure drop 20" H_2O

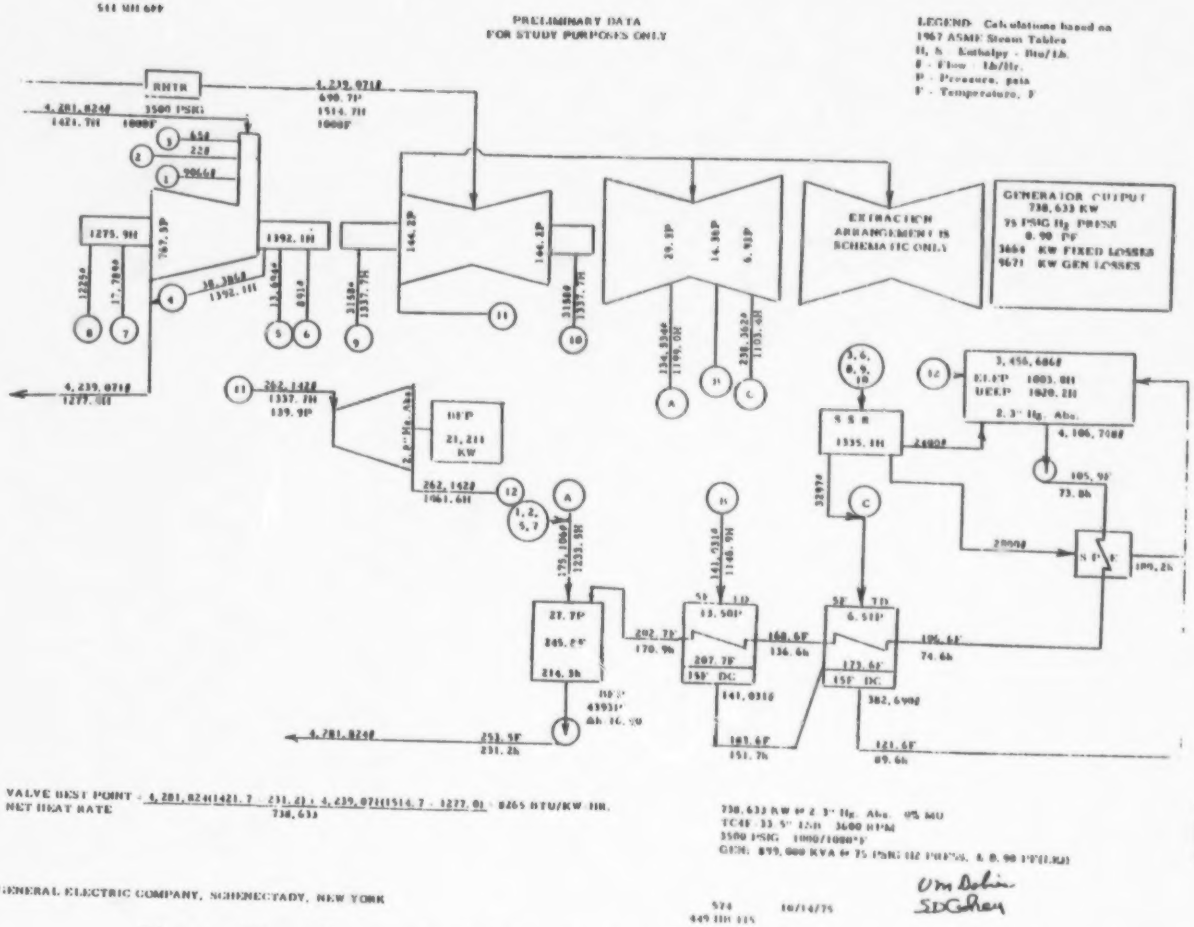

511 MH 699
PRELIMINARY DATA
FOR STUDY PURPOSES ONLY
LEGEND- Calculations based on
1967 ASME Steam Tables
H, h - Enthalpy - Btu/Lb.
# - Flow - Lb/Hr.
P - Pressure, psia
F - Temperature, F
RHTR
4,281,824#
1421.7H
3500 PSIG
1000F
4,239,071#
690.7P
1514.7H
1000F
654
228
9066#
1275.9H
767.5P
1392.1H
38,386#
1392.1H
1229#
17,780#
13,694#
891#
3158#
1337.7H
164.2P
164.2P
3158#
1337.7H
29.3P
14.36P
6.93P
134,934#
1199.0H
238,362#
1103.4H
EXTRACTION
ARRANGEMENT IS
SCHEMATIC ONLY
GENERATOR OUTPUT
738,633 KW
75 PSIG H2 PRESS
0.90 PF
3664 KW FIXED LOSSES
9671 KW GEN LOSSES
4,239,071#
1277.0H
262,142#
1337.7H
139.9P
2.8" Hg. Abs.
BFP
21,211
KW
262,142#
1061.6H
1, 2,
5, 7
175,106#
1233.5H
27.7P
245.2F
214.3h
BFP
4393P
Δh 16.9
4,281,824#
253.5F
231.2h
141,031#
1148.9H
5F
TD
13.50P
207.7F
15F DC
202.7F
170.9h
168.6F
136.6h
141,031#
183.6F
151.7h
5F
TD
6.51P
173.6F
15F DC
106.6F
74.6h
382,690#
121.6F
89.6h
3, 6,
8, 9,
10
S S R
1335.1H
2480#
3297#
2000#
S P E
109.2h
3,456,686#
ELEP
1003.0H
UEEP
1020.2H
2.3" Hg. Abs.
4,106,708#
105.9F
73.8h
VALVE BEST POINT NET HEAT RATE = 4,281,824(1421.7 - 231.2) + 4,239,071(1514.7 - 1277.0) / 738,633 = 8265 BTU/KW HR.
738,633 KW @ 2.3" Hg. Abs. 0% MU
TC4F 33.5" LSB 3600 RPM
3500 PSIG 1000/1000°F
GEN: 899,000 KVA @ 75 PSIG H2 PRESS. & 0.90 PF(LAG)
574
449 HB 115
10/14/75
GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK

Figure 32. Steam Turbine Cycle Heat Balance PFB – 1650 F

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Table 64

COOLING TOWER PERFORMANCE

Design heat duty	3600 MBtu/hr
Wet bulb	51.5 F
Condensing at 2.3 in. Hga	105.9 F
Hot water to tower	100.9 F
Cold water return	70.2 F
Range	30.7 F
Approach	18.7 F
Water flow	234,555 gal/min
Fan power	2.53 MW
Pump power	4.40 MW
Cells	22

Each cell: 36 feet long, 75 feet wide,
47 feet high, 1 fan

Table 65

SYSTEM OUTPUT
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED
1650 F

STEAM CYCLE OUTPUT (MW_e) (MW_e - 60 Hz AC)	738.63
TOTAL PRESSURIZING TURBINE OUTPUT (MW_e)	205.00
TOTAL GROSS OUTPUT (MW_e)	943.63
TOTAL AUXILIARY LOSSES (MW_e) INCLUDING TRANSFORMER LOSSES	39.86
NET POWER PLANT OUTPUT (MW_e - 60 Hz AC - 500 kV)	903.77

cleanup or turbine design, it will be necessary to employ alloys that are more corrosion resistant or apply coatings to surfaces in the hot gas stream.

The steam turbine represents a mature technology, and significant materials problems are not anticipated.

4. PLANT ARRANGEMENT

Plot Plan

The plant arrangement on its plot is based on storage of a 60-day supply of coal and a capacity to hold ash for 15 days. A series of ponds contain run off water from the site and provide for treatment of all water returned to the North River. The basic plot dimensions are one-half mile by three-tenths of a mile.

Figure 33 shows the total plant area of 108 acres in the small section, and the main area in detail.

Coal and Dolomite Handling

Coal is received by rail and is unloaded to two conical storage piles. The compacted dead storage coal pile is 60 ft high with a base measuring about 1240 ft by 416 feet. This stores 412,000 tons of coal for recovery by use of dozer tractors. The two conical live storage piles have a base diameter of about 312 ft, and contain a total of 114,700 tons of coal, with 26,000 tons available by gravity feed through under-pile vibrating feeders. Dolomite is stored in a single storage pile of 235,000-ton total capacity with 11,800 tons available by gravity flow through under-pile vibrating feeders.

The coal from the active storage pile is fed at 365 tons/hr to a conveyor belt by vibrating feeders located under the active storage pile. Magnetic separators at the distribution bid remove the tramp iron. Oversize coal is screened out, crushed, and then fed back to the distribution bin. The distribution bin is equipped with four coal outlets, which feed the coal to four conveyor belts; each belt feeds the coal to two silos. A set of four silos feed the coal to an associated conveyor belt for the transport and distribution of coal to any two of the three parallel sets of half plant capacity dryers and crushers. This provides one redundant set of dryer and crusher for reliability and maintenance purposes. During startup, and under upset operations, coal can also be supplied to combustors for drying the coal and limestone in place of hot air from the spent solids cooler. Dolomite is handled similarly at a rate of 168 tons/hr.

The coal and dolomite are delivered separately to bins at each boiler module. The coal and dolomite are not premixed for injection to the fluid bed. For these PFB boilers the two materials are injected separately by Petrocarb injection systems that are part of the PFB boiler modules.

Solid Wastes Handling

Spent dolomite and ash are collected at the PFB boiler modules at a nominal rate of 155 tons/hr. This residue leaves the boilers at 1600 F and is air-cooled to 250 F prior to being conveyed to storage bins at the rail spur. A solid waste dry storage capacity of 55,800 tons is provided by six storage silos.

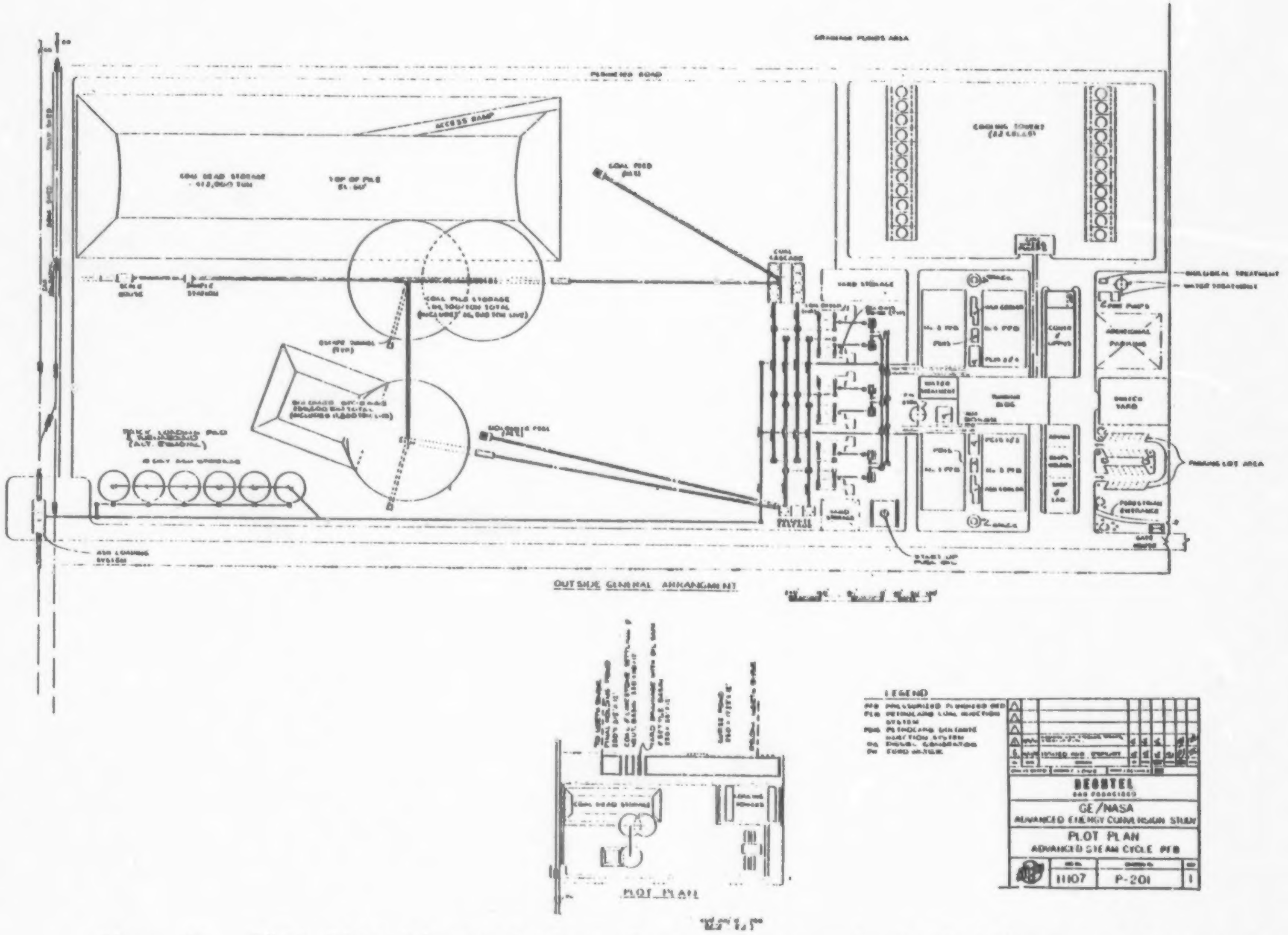
PERIMETER ROAD
ACCESS RAMP
COAL FEED
SCALE HOUSE
SAMPLE STATION
COAL PILE STORAGE
COOLING TOWER
PARKING LOT AREA
START UP FUEL OIL
OUTSIDE GENERAL ARRANGEMENT
PLOT PLAN
LEGEND
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
PLOT PLAN
ADVANCED STEAM CYCLE PFB
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Figure 33. Plot Plan Advanced Steam Cycle – Pressurized Fluidized Bed (Bechtel)

General Arrangement

The arrangement of the four PFB modules about the turbine building is shown in Figure 34. The ground floor plant indicates the small size of the No. 3 PFB furnace as compared to its cyclones and granular bed fine filters.

Plant Elevation

The plant elevation view through the turbine building and one PFB module is presented in Figure 35. The stack of fluidized beds is contained in the 13-ft diameter pressurized tower, which stands 130 ft high. Four of eight cyclone separators and eight of sixteen granular bed filters are shown.

The gas turbine is located at ground level between the two rows of filters. The exhaust passes through the economizer en route to a stack on each side of the power plant.

Electrical Schematic

A single line electric diagram showing major electrical equipment is presented in Figure 36. Four 51.25 MW gas turbine-generators feed the 25 kV bus through step-up transformers. The 738.6 MW steam turbine-generators feeds the 25 kB bus directly. Two main transformers feed the 500 kV transmission line.

Two 13.8 kV auxiliary buses may be connected to the main bus through a transformer or to the start-up transformer. Subsidiary buses operate at 4.16 kV and 480 kV. The emergency diesel feeds the 480 kV critical service bus.

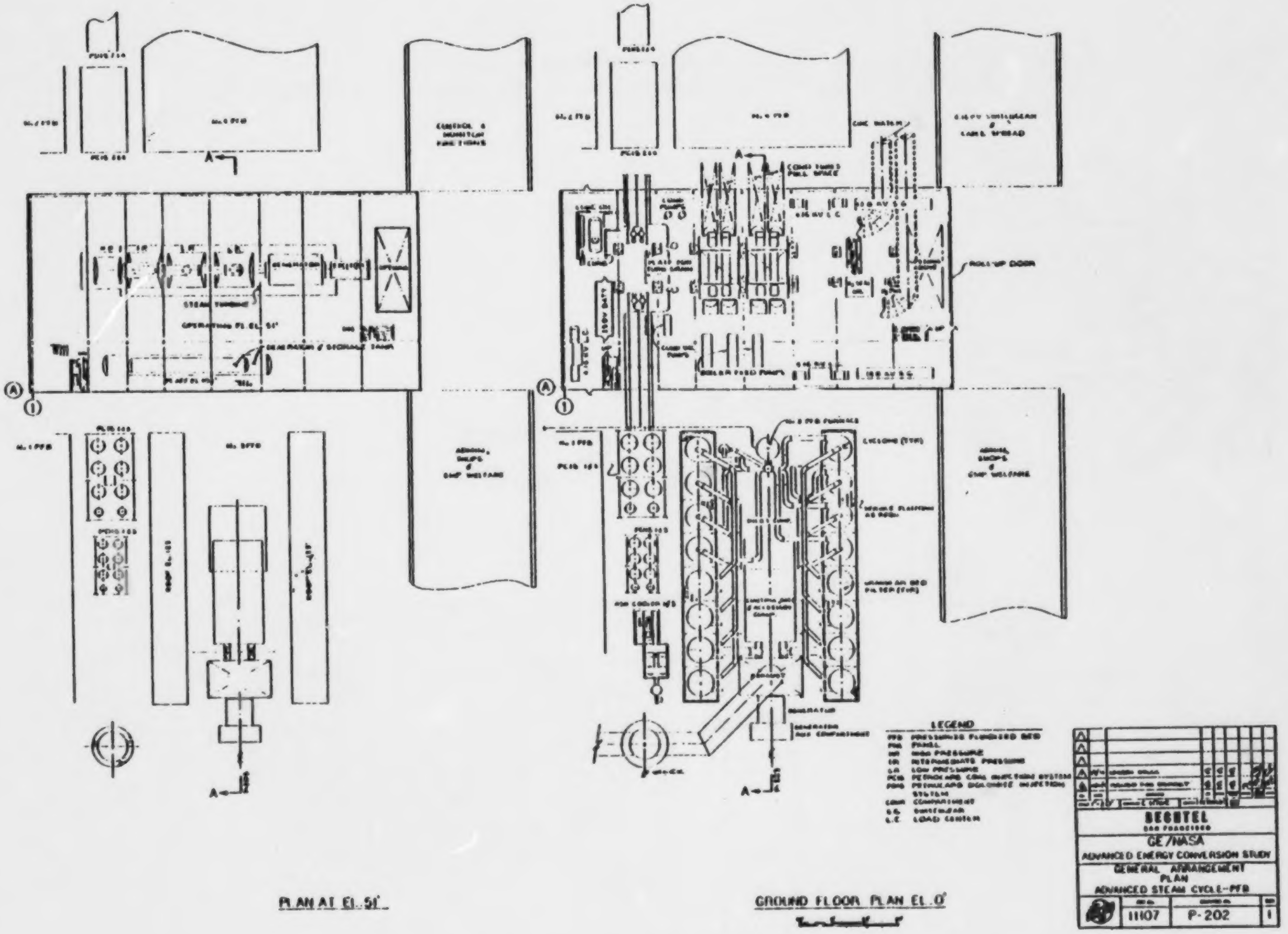
ROLL-UP DOOR
PLAN AT EL. 51'
GROUND FLOOR PLAN EL. 0'
LEGEND
PFB PRESSURIZED FLUIDIZED BED
PNL PANEL
HP HIGH PRESSURE
IP INTERMEDIATE PRESSURE
LP LOW PRESSURE
COMP COMPARTMENT
LC LOAD CENTER
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
GENERAL ARRANGEMENT
PLAN
ADVANCED STEAM CYCLE-PFB
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Figure 34. General Arrangement Plan Advanced Steam Cycle – Pressurized Fluidized Bed (Bechtel)

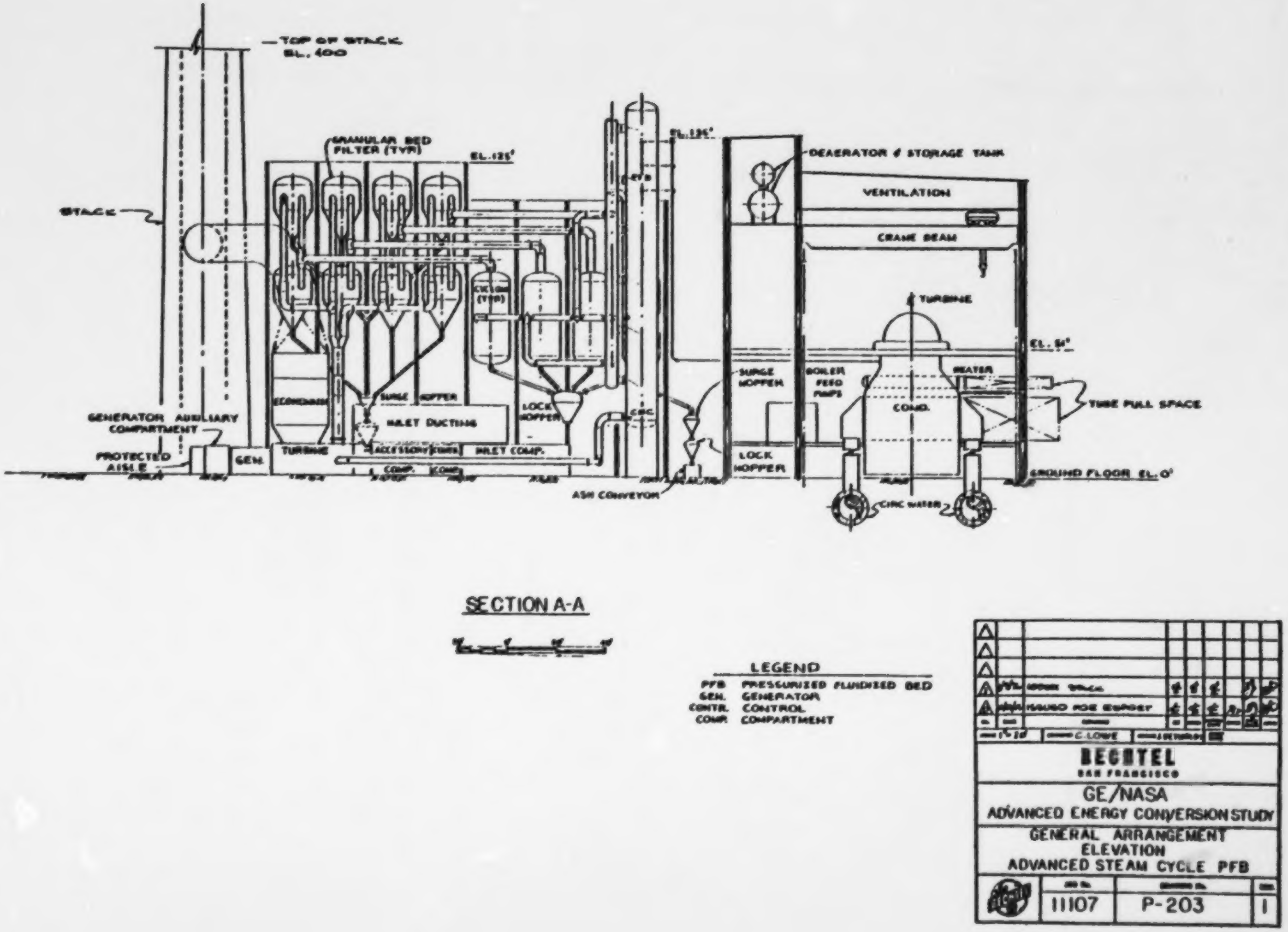
TOP OF STACK EL. 400
STACK
GRANULAR BED FILTER (TYP)
EL. 125'
EL. 135'
DEAERATOR & STORAGE TANK
VENTILATION
CRANE BEAM
TURBINE
EL. 51'
HEATER
TUBE PULL SPACE
SURGE HOPPER
BOILER FEED PUMPS
COND.
LOCK HOPPER
GROUND FLOOR EL. 0'
CIRC WATER
ASH CONVEYOR
CYCLONE (TYP)
LOCK HOPPER
PFB
CFC
ECONOMIZER
SURGE HOPPER
INLET DUCTING
TURBINE
ACCESSORY COMP.
INLET COMP.
GENERATOR AUXILIARY COMPARTMENT
PROTECTED AISLE
GEN.
SECTION A-A
LEGEND
PFB PRESSURIZED FLUIDIZED BED
GEN. GENERATOR
CONTR. CONTROL
COMP. COMPARTMENT
ISSUED FOR REPORT
C. LOWE
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
GENERAL ARRANGEMENT
ELEVATION
ADVANCED STEAM CYCLE PFB
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Figure 35. General Arrangement Elevation Advanced Steam Cycle – Pressurized Fluidized Bed (Bechtel)

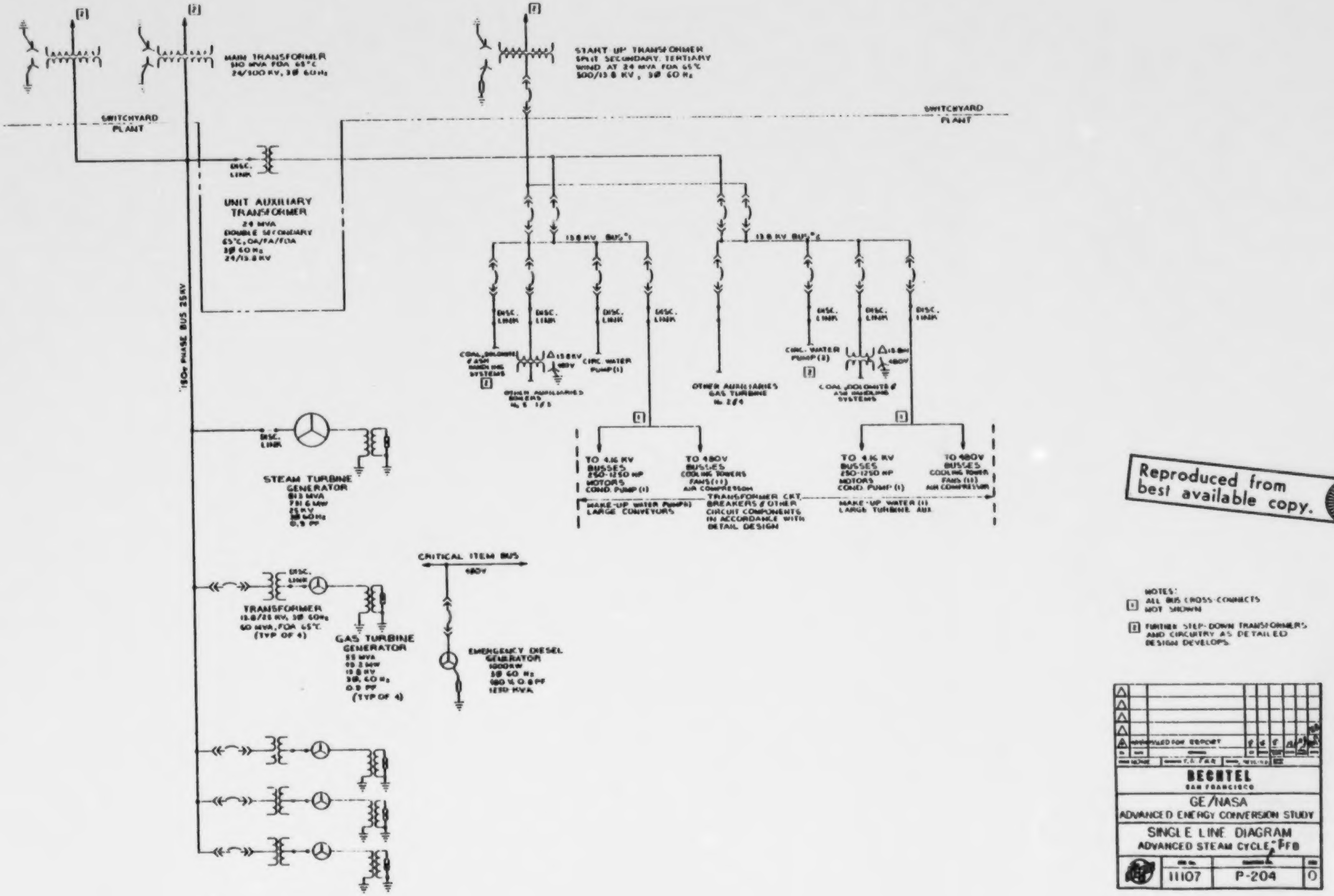
MAIN TRANSFORMER
510 MVA FOA 65°C
24/500 KV, 3Ø 60Hz
START UP TRANSFORMER
SPLIT SECONDARY TERTIARY
WIND AT 24 MVA FOA 65°C
500/13.8 KV, 3Ø 60 Hz
SWITCHYARD
PLANT
DISC. LINK
UNIT AUXILIARY
TRANSFORMER
24 MVA
DOUBLE SECONDARY
65°C, OA/FA/FOA
3Ø 60 Hz
24/13.8 KV
ISO PHASE BUS 25KV
13.8 KV BUS 1
13.8 KV BUS 2
COAL, DOLOMITE & ASH HANDLING SYSTEMS
13.8 KV
480V
CIRC. WATER PUMP (1)
OTHER AUXILIARIES BOILERS No. 1 & 3
OTHER AUXILIARIES GAS TURBINE No. 2 & 4
CIRC. WATER PUMP (2)
COAL, DOLOMITE & ASH HANDLING SYSTEMS
TO 4.16 KV BUSSES 250-1250 HP MOTORS COND. PUMP (1)
TO 480V BUSSES COOLING TOWERS FANS (11) AIR COMPRESSOR
MAKE-UP WATER PUMP(S) LARGE CONVEYORS
TRANSFORMER CKT. BREAKERS & OTHER CIRCUIT COMPONENTS IN ACCORDANCE WITH DETAIL DESIGN
MAKE-UP WATER (1) LARGE TURBINE AUX.
STEAM TURBINE GENERATOR
813 MVA
731.6 MW
25 KV
3Ø 60 Hz
0.9 PF
TRANSFORMER
13.8/25 KV, 3Ø 60Hz
60 MVA, FOA 65°C
(TYP OF 4)
GAS TURBINE GENERATOR
55 MVA
49.2 MW
13.8 KV
3Ø, 60 Hz
0.9 PF
(TYP OF 4)
CRITICAL ITEM BUS
480V
EMERGENCY DIESEL GENERATOR
1000KW
3Ø 60 Hz
480 V, 0.8 PF
1250 KVA
NOTES:
1 ALL BUS CROSS-CONNECTS NOT SHOWN
2 FURTHER STEP-DOWN TRANSFORMERS AND CIRCUITRY AS DETAILED DESIGN DEVELOPS.
ISSUED FOR REPORT
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
SINGLE LINE DIAGRAM
ADVANCED STEAM CYCLE - PFB
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Figure 36. Electrical Diagram for Advanced Steam – PFB System (Bechtel)

5. SYSTEM PERFORMANCE AND COSTS

Performance

The performance margins commonly applied to steam power plants cannot be tolerated in a closely integrated plant such as this. The heat balances presented for PFB, gas turbine, and steam turbine must all be guaranteed performance points. Table 65 presents the resulting gross generation, auxiliary power loss, and net station output for plant configurations with 1650 F mainbeds. The auxiliaries are of the order of 4 percent of generation as compared to 7 percent for AFB power plants.

Auxiliary Losses

The detailed auxiliary losses are presented in Table 66. By virtue of the gas turbines supplying the energy to force gas through the PFB and hot gas cleanup system, there is no electrical auxiliary loss attributed to that service; this factor accounts for the markedly reduced electrical auxiliary loads for PFBs as compared to the AFB power plant.

Costs--General

Costs were synthesized from major components costs, BOP material costs, and BOP labor costs. Items made up of numerous smaller components are presented by enumeration of the total cost and unit count for each of the subcomponents. An equipment list for BOP components identifies all major items. A detailed breakdown of BOP labor man-hours and material costs completes identification of all material and construction and installation costs. Thereafter these costs were combined with major component costs to arrive at total plant costs.

Costs--Major Components

The steam turbine-generator would be purchased at a price of $25 million, and each gas turbine would be purchased as a complete unit for $6.41 million. In contrast, the steam generator comprises four PFB modules, auxiliary units serving each PFB, conveyor and solids equipment serving pairs of PFB modules, and solids preparation equipment providing three units where any two can service the entire plant. Equipment lists for the PFB steam generator system are presented as Tables 67, 68, and 69.

PFB Major Component Characteristics (1650)

Subsystems costs and weights are presented in Table 70 for the steam turbine-generator and for the PFB modules exclusive of their solids handling equipment. The gas turbine, its economizer, and the hot gas filtering system are also enumerated.

Table 66

AUXILIARY LOSS BREAKDOWN
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED
1650 F

ITEM	ASSUMPTIONS	NO. OF UNITS	TOTAL MW_e
FURNACE			
FANS FOR DRYERS (COAL DOLOMITE, SOLIDS)		2	4.18
COAL CRUSHER		2	0.74
DOLOMITE CRUSHER		2	0.33
INJECTOR COMPRESSOR		8	4.03
FILTER		8	1.11
TURBINES	0.33% OF STEAM TURBINE, kW	1	2.37
	1% OF GAS TURBINE, kW	4	2.16
PUMPS			
CONDENSATE	Δ P = 185 PSIA	2	9.95
CIRC. WATER	PROPORTION TO COOLING DUTY	3	4.40
SERVICE WATER	A/E ESTIMATE	2	0.89
INTAKE WATER	A/E ESTIMATE	2	0.94
SOLIDS HANDLING	BASED ON RATES AND LIFTS	1	2.17
"HOTEL" LOAD	0.88% OF GENERATED kW	1	8.34
COOLING TOWER FANS	VENDORS VALUE	22	2.53
TRANSFORMER LOSS	0.5% OF GENERATED kW	2	4.72
	TOTAL AUXILIARY POWER =		39.86

Table 67

SOLIDS HANDLING EQUIPMENT LIST AND COSTS--PFB

Subsystems	Cost in 1975 $	Plant Requirement Number	Plant Requirement M$
COAL PROCESSING & FEEDING			
1 - Dryer System @ 182-1/2 TPH	$ 884,002	3	
1 - Crusher & 2 Screens	159,250	3	
1 - Distribution Bin @ Crusher	31,200	3	
2 - Vibrating Feeders @ 92 TPH	11,700	3	
2 - Surge Bins @ 7600 ft^3	59,487	3	
2 - Bin Activators	45,500	3	
2 - Feeders (Vibrating) @ 365 TPH	14,301	3	
2 - Coal Distribution Boxes	10,400	3	
2 - Petrocarb Coal Injector System	7,198,354	2	
Section Subtotal =	$8,414,194		18.04
DOLOMITE PROCESSING & FEEDING			
1 - Dryer System @ 84 TPH	468,000	3	
1 - Crusher & 2 Screens	92,482	3	
1 - Distribution Bin @ Crusher	14,929	3	
2 - Vibrating Feeders @ 42 TPH	10,140	3	
2 - Surge Bins @ 1867 ft^2	28,466	3	
2 - Bin Activators	41,600	3	
2 - Feeders (Vibrating)	12,740	3	
2 - Dolomite Distribution Boxes	7,800	3	
2 - Petrocarb Injection Systems	3,851,375	2	
Section Subtotal =	4,527,532		9.73
SPENT BED MATERIAL			
2 - Throttle Valves for Bed Drains	23,660	2	
2 - 190 ft^3 Surge Hoppers	86,579	2	
4 - Lock Hopper Valves	69,159	2	
2 - 580 ft^3 Lock Hoppers	170,301	2	
2 - High Temp. Feeders (Vibrating) 34 TPH	28,600	2	
2 - Surge Bins @ Solids Coolers	40,404	2	
2 - Solids Coolers with fans and cyclones for $24(10)^6$ Btu/hr.	299,000	2	
4 - Air Lock Valves for Coolers @ 34 TPH	72,800	2	
Section Subtotal =	790,503		1.58
CONTROL SYSTEMS			
Solids Handling Equipment	149,058	2	
Section Subtotal	149,058		0.30
Total for PFB Solids Handling			29.65

Table 68

HOT GAS CLEANUP AND AIR EQUIPMENT LIST AND COSTS--PFB

	Cost in 1975 $	Plant Requirement	
		Number	M$
HOT GAS CLEANUP			
16 - Two in One Cyclones for Beds	$ 8,127,592		
4 - 145 ft^3 Collecting Hoppers	106,781		
32 - Trickle Valves & Dip Legs	228,880		
8 - Lock Hopper Seal Valves	137,278		
4 - 290 ft^3 Lock Hoppers	173,161		
4 - Fines Injection Systems	519,999		
4 - Injection System Valves	68,639		
2 - Two in One Cyclones for CBC	532,011		
2 - 290 ft^3 Collecting Hoppers	86,579		
4 - Trickle Valves & Dip Legs	28,860		
4 - Lock Hopper Seal Valves	68,639		
2 - 580 ft^3 Lock Hoppers	170,301		
2 - High Temp. Feeders (Vibrating)	31,200		
2 - Surge Bins for Dust Coolers	40,404		
4 - Airlock Valves for Dust Coolers	57,200		
2 - CBC Dust Coolers	260,000		
32 - Granular Bed Filters	20,893,579		
4 - Fines Letdown & Removal Systems for Granular Beds	721,499		
Section Subtotal =	$32,252,522	2	64.51
HIGH PRESSURE AIR			
2 - Air Dryer Precoolers	174,200	2	
4 - Air Dryers	349,803	2	
4 - Booster Compressors	416,000	2	
4 - 400 ft^3 Receivers 300#	50,897	2	
4 - Air Compressors for Granular Beds	193,533	2	
2 - 400 ft^3 Receivers 400#	28,628	2	
1 - Booster Compressor Spare	104,000	1	
1 - Air Compressor Spare	48,383	1	
Section Subtotal =	1,365,444		2.58

Table 69

HEAT EXCHANGE EQUIPMENT LIST AND COSTS - PFB

	M$ per Module	M$ Plant
PFB heat exchange and pressure parts	2.213	
PFB containment shell and nozzles	0.566	
PFB fuel injection and air parts	0.237	
PFB controls	0.567	
PFB petrocarb cooler economizer E_x	0.089	
PFB module	3.67	14.68
Gas turbine economizer E_Y	0.627	2.51

Table 70

MAJOR COMPONENT AND SUBSYSTEM WEIGHTS AND COSTS
SUMMARY
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED

Major Component or Subsystem	Weight (FOB) M LB	Component or Subsystem Costs (FOB) M$	Output Or Duty	Cost Per Unit Output Or Duty	Cost Per LB
PRIME CYCLE					
STEAM TURBINE-GENERATOR	6.5	25	738.6 MW_e	33.85 $/$kW_e$	3.85
(GENERATOR ALONE)	(0.94)	-	-	-	-
PFB MODULE	0.57	3.67	244.1 MW_{th}	15.03 $/$kW_{th}$	6.44
ECONOMIZER	0.44	0.63	90.9 MW_{th}	6.9 $/$kW_{th}$	1.43
PRESSURIZING SYSTEM					
GAS TURBINE-GENERATOR	0.49	6.41	51.25 MW_e	125 $/$kW_e$	13.22
(GENERATOR ALONE)	(0.18)	-		-	-
HOT GAS FILTERING	-	16.13	-	-	-

Table 71 presents the characteristics of the PFB module heat exchange and pressure containment parts and the gas turbine exhaust economizer. The average heat flux is high compared to conventional boilers and is three times the average for the AFB unit. However, the peak heat flux is very much less than peak values for conventional boilers. As a result of these conservative values the PFB heat exchange surfaces are expected to have service life far greater than the hottest parts of conventional furnaces and boilers. The economizer operates with low heat exchange temperature differences that require very great surface area because of the low heat flux.

Equipment List-Balance of Plant (1650)

The specifications for the BOP equipment are listed in Table 72. Electric motor drives for fans and pumps anticipate a margin of 10 percent flow, 20 percent pressure rise, and 30 percent power. As a result these motors are sized for continuous duty at levels above the 100 percent plant operating point.

Capital Costs-Balance of Plant (1650 F)

Table 73 presents the AE's detailed breakdown of the direct manual field labor in thousands of man-hours, and of BOP material cost in thousands of dollars for each major category of the balance of plant. In using these data an average hourly field labor rate of $11.75 in mid-1975 dollars converts man-hours to dollars. Where field indirect labor is allocated to individual items rather than the total labor for the job, it will be apportioned as 90 percent of the direct field labor cost or at a rate of $10.58 per direct labor hour. All material and labor costs are based on mid-1975 costs.

The seven major categories used by the AE relate to the principal field labor skills to be applied. A modified subdivision of costs was made using the following categories:

1. Land improvements and structures
2. Coal handling
3. Prime cycle plant equipment
4. Bottoming cycle (not applicable to PFB plant)
5. Electrical plant and instrumentation

After the title of each item or major category in Table 73, the appropriate second category is given in parenthesis.

Plant Cost Estimates

The installed costs of major system components are presented in Table 74. Those elements related to heat release cost a total of $75 million. They are the coal and solids handling equipment, the PFB furnace modules, and the economizers. The steam turbine-generator along with its feedwater heaters and pumps costs half that amount. The gas turbines with hot gas filter system cost $95 million.

Table 71

HEAT EXCHANGER CHARACTERISTICS
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED

Heat Exchanger	No. of Units	Vessel Size or Type	Output or Duty Per Unit M Btu	Efficiency or Effectiveness	Unit Surface Area Ft^2	Unit Weight (FOB) LB x 10^{-3}	Unit Cost (FOB) M$	Heat Flux Average Btu $HR^{-1}Ft^{-2}$
PFB MODULE	4	13' dia x 116'	833	-	22361	568.6	2.213*	37252
ECONOMIZER	4	23' x 38' x 10'	310	0.92	179326	440	0.627	1726

*HEAT EXCHANGE AND PRESSURE PARTS ONLY

Table 72 (page 1 of 4)

BALANCE OF PLANT EQUIPMENT LIST
ADVANCED STEAM PLANT, PRESSURIZED FLUIDIZED BED, 1650 F

EQPT. NO.	SERVICE	DESCRIPTION
	1. Coal, Dolomite and Ash Handling Systems	
C-1	Coal Conveyor Belt	60 in wide, 344 ft long, 3000 tph, 365 hp
C-2	" " "	" " " 575 ft " " " 642 hp
C-3	" " "	" " " 190 ft " " " 420 hp
C-4	" " "	42 in " 1000 ft " 500 tph, 144 hp
C-5	" " "	" " " 610 ft " " " 111 hp
C-6	Dolomite Conveyor Belt	60 in " 375 ft " 3000 tph, 163 hp
C-7	" " "	36 in " 1035 ft " 220 tph, 46 hp
C-8	" " "	" " " 830 ft " " " 36 hp
C-11	Vibrating Feeders for Car Unloading (6 req'd)	Rating 0-750 tph Dimension from Layout
C-12	Coal Belt Scale	0-3000 tph, 60 in Belt
C-13	Coal and Dolomite Sampling System	0-3000 tph, 60 in Belt
C-14	Coal Lump Crusher (3 req'd)	0-10 tph, 10 in Lumps
C-15	Dolomite Lump Crusher (3 req'd)	0-10 tph, 10 in Lumps
C-16	Magnetic Coal Cleaner (3 req'd)	500 tph
C-17	Magnetic Dolomite Cleaner (3 req'd)	125 tph
C-18	Coal and Dolomite Dust Control System	4-6000 cfm Bag Type Dust Collector
C-19	CO_2 Fire Protection System	Adequate to Service Item C-18 Bag-houses

Table 72 (page 2 of 4)

EQPT. NO.	SERVICE	DESCRIPTION
C-20	Vibrating Feeders for Dolomite Pile (4 req'd)	0-220 tph
C-21	Vibrating Feeders for Coal Piles (8 req'd)	0-200 tph
C-22	Coal Silos (8 req'd)	375 ton each
C-23	Dolomite Silos (2 req'd)	650 ton each
C-24	Ash Storage Silos (6 req'd)	Total Volume 2,800,800 ft^3 80 ft dia., 95 ft high
	2. Electrical Systems	
E-1	Main Transformers (2 req'd)	510 MVA, FOA 65°C 24/500 kV, 3ϕ, 60 Hz
E-2	Unit Aux Transformer	24/13.8 kV, 3ϕ, 60 Hz Double Secondary 24/24 MVA, FOA 65°C
E-3	Start-up Transformer	500/13.8 kV, 3ϕ, 60 Hz Split Secondary Tertiary Winding at 24 MVA, FOA 65°C
E-4	Auxiliary Diesel Generator	1000 kW, 3ϕ, 60 Hz, 480 V, 0.8PF, 1250 kVA
E-5	Miscellaneous 480/277 V LCC Transformers (14 req'd)	13.8 kV / 480/277 V, 3ϕ, 60 1680 kVA, FOA, 65°C
E-6	4.16 kV LCC Transformers (2 req'd)	13.8 / 4.16 kV, 3ϕ, 60 Hz 8,000 kVA, 65°C
E-7	Gas-Turbine Output Transformers (4 req'd)	13.8 / 25 kV, 3ϕ, 60 Hz, 60 MVA, FOA, 65°C, 54 MW

Table 72 (page 3 of 4)

3. Main Fluid Systems

EQPT. NO.	SERVICE	DESCRIPTION
F-1	Main Condenser	3.81×10^5 ft^2 of heat transfer area: Std Materials in other respects same as AFB but with # of tubes scaled down in proportion to heat transfer area.
F-2	Piping:	
	Circulating Water	I.D. = 123 in
	Main Steam*	I.D. = 6.31 in, tm = 1.628 in
	Boiler Feedwater*	I.D. = 6.73 in, tm = 1.077 in
	Cold Reheater RHI*	I.D. = 11.59 in, tm = 0.29 in
	Hot Reheater RHO*	I.D. = 14.2 in, tm = 0.631 in

EQPT. NO.	Feedwater Heaters	Shell psia/°F	Tube psia/°F	Flow lb/hr	Heat Transfer Area ft^2
F-3					
	L.P. #1	6/171	160/166	4.06×10^6	17,315
	L.P. #2	13/205	160/200	4.06×10^6	13,928
	D.F.T.	4.3×10^6 lbs/hr @ 250°F			

EQPT. NO.	SERVICE	DESCRIPTION
F-4	Main Condenser Pumps and Motors (2 req'd)	640 hp, 4,300 gpm, 410 ft TDH
F-5	Boiler Feed Pumps (3 req'd) Turbine Driven	9,850 hp, 3,450 gpm, 10,070 ft TDH
F-6	Main Circulation Pumps and Motors (3 req'd)	1920 hp, 90,000 gpm, 75 ft TDH
F-7	Cooling Towers (22 cells)	234,200 gpm

*Size based on flow at each boiler

Table 72 (page 4 of 4)

EQPT. NO.	SERVICE	DESCRIPTION
F-8	Air Duct, Compressor to PFB combustor, (one/PFB)	30 in I.D.
F-9	Gas Ducts	Steel Pipe with 9 in Refractory lining
	Manifold to PFB (one/PFB)	36 in I.D.
	Manifold to Cyclone (8/PFB)	20 in I.D.
	Cyclones to Granular B. F. (8/PFB)	20 in I.D.
	Granular Bed Filter to Turbine (16/PFB)	14 in I.D.
	(20/PFB)	20 in I.D.
	(2/PFB)	28 in I.D.
F-10	Exhaust Stacks (2 req'd)	17.5 ft dia x 400 ft high

Table 73 (page 1 of 7)

BALANCE OF PLANT ESTIMATE DETAIL
ADVANCED STEAM PLANT, PRESSURIZED FLUIDIZED BED, 1650 F

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
1.0	PFB STEAM GENERATORS (3)		
1.1	Steam Generator Erection		
-	Erect only (supply by others): includes PFB tower skirt; PFB towers; piping connections at tower; insulation	22	
-	Supply and erect: includes tower access steel; miscellaneous materials and labor operations	6	70
1.2	Steam Generator Auxiliaries		
-	Erect only (supply by others): includes coal and dolomite Petrocarb injection systems with injection air compressors and auxiliaries	22	100
-	Supply and erect: includes support steel for Petrocarb systems; coal and dolomite piping from Petrocarb systems to PFB towers	221	890
1.3	Hot Gas Cleanup		
-	Erect only (supply by others): includes cyclones; hoppers and surge bins; valves; feeders and injection systems; dust coolers; granular bed filters; granular bed blowback air compressors and auxiliaries	38	100
-	Supply and erect: includes support steel for hot gas cleanup equipment; access steel	61	1,940
		370	3,100

Table 73 (page 2 of 7)

			Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
2.0	TURBINE GENERATORS (3)			
	2.1	Steam Turbine Generator		
	-	Erect only (supply by others): includes 732 MWe steam turbine: generator; exciter; auxiliary equipment; integral steam and auxiliary piping; insulation; miscellaneous labor operations	105	100
	2.2	Gas Turbine/Compressor/Generators		
	-	Erect only (supply by others): includes gas turbine compressors with 50 MWe generators (4)	40	100
			145	200
3.0	PROCESS MECHANICAL EQUIPMENT			
	3.1	Boiler Feedwater Pumps (3)		
	-	Supply and install: includes turbine-driven main feedwater pumps and drivers (3 @ $770,000 ea.)	8	2,430
	3.2	Main Circ. Water Pumps (3)		
	-	Supply and install: includes main circ. water pumps and motors (3 @ $265,000 ea.)	3	830
	3.3	Other Pumps (3)		
	-	Supply and install: includes condensate pumps and motors (2 @ $100,000 ea.); and other pumps and drivers not listed elsewhere	4	590

Table 73 (page 3 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.8	Coal Handling		
-	Supply and erect: includes railcar dumping equipment; dust collectors; primary crushing equipment; belt scale; sampling station; magnetic cleaners; mobile equipment; conveyors to pile; reclaiming feeders; conveyors and bucket elevators to dryers and grinders; recirculating conveyors at grinders; conveyors to Petrocarb; bucket elevators at Petrocarb	80	6,150
3.10	Dolomite Handling (2)		
-	Erect only (supply by others): includes dolomite dryers (3); support and access steel for dryers; dolomite grinders (3); screens at grinders	13	10
-	Supply and erect: includes magnetic cleaners; conveyor to dolomite pile; reclaiming feeders; conveyors to cascade; dolomite cascade; conveyors and bucket elevators to dryers; conveyors and bucket elevators to grinders; conveyors and bucket elevators to Petrocarb	43	2,240
3.11	Spent Solids Handling (2)		
-	Erect only (supply by others): includes spent solids valves; hoppers; feeders; fans; cyclones; conveyor to coolers; ash coolers (2)	11	30
-	Supply and erect: includes ash cooler accessories and bucket elevators; ash conveyors; ash storage silos (6) with feeders; unloaders and foundations; railcar loading equipment	85	3,540

Table 73 (page 4 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
3.12	Cooling Towers (3)		
-	Supply and erect: includes mechanical draft towers with fans and motors	57	2,450
3.13	Other Mechanical Equipment (3)		
-	Supply and install: includes water treatment and chemical injection; air compressors and auxiliaries; fuel oil ignition and warm-up; screenwell; miscellaneous plant equipment; equipment insulation	34	1,820
		535	26,200
4.0	ELECTRICAL (5)		
4.1	Main Transformers	11	2,960
-	includes main power transformers and transformers at gas turbine generators		
4.2	Other Transformers and Main Bus	18	1,240
-	includes startup transformer; station service transformers; generator main bus		
4.3	Switchgear and Control Centers	25	2,050
-	includes switchgear and load centers; motor control centers; local control stations; distribution panels, relay and meter boards		
4.4	Other Electrical Equipment	373	2,140
-	includes communications; grounding; cathodic and freeze protection; lighting; preoperational testing		

Table 73 (page 5 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
4.5	Auxiliary Diesel Generator	2	110
-	includes diesel generator, batteries and associated d.c. equipment		
4.6	Conduit, Cable Trays, Wire and Cable	381	2,500
		810	11,000
5.0	CIVIL AND STRUCTURAL		
5.1	Concrete Substructures and and Foundations (1)	395	3,260
-	includes turbine building substructure; PFB base mats; coal, dolomite and ash handling foundations, pits and tunnels; miscellaneous equipment foundations; auxiliary buildings substructures; miscellaneous concrete		
5.2	Superstructures (1)	220	6,130
-	includes turbine building; auxiliary yard buildings		
5.3	Earthwork (1)	135	300
-	includes building excavations; coal, dolomite and ash handling excavations; circ. water system excavations; PFB foundation excavations; miscellaneous foundtion excavations; dewatering and piling		
5.4	Cooling Tower Basin and Circ. Water System (3)	100	1,510
-	includes circ. water pump pads, riser and concrete envelope for pipe; cooling tower basin; circ. water pipe; cooling tower miscellaneous steel and fire protection		
		850	11,200

Table 73 (page 6 of 7)

			Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
6.0	PROCESS PIPING AND INSTRUMENTATION			
	6.1	Steam and Feedwater Piping (3)	50	2,400
	-	includes main steam; extraction steam; hot reheat; cold reheat; feedwater and condensate large piping, valves and fittings		
	6.2	Hot Gas Large Pipe (3)	120	5,700
	-	includes PFB compressed air feed; PFB hot gas discharge; cyclone and granular bed filter piping; gas turbine inlet piping		
	6.3	Other Large Piping (3)	195	3,350
	-	includes auxiliary steam; process water; auxiliary systems; spent solids piping		
	6.4	Small Piping (3)	125	1,100
	-	includes all piping, valves and fittings of 2-inch diameter and less		
	6.5	Hangers and Misc. Labor Operations (3)	390	1,900
	-	includes all hangers and supports; materials handling; scaffolding; misc. labor operations		
	6.6	Pipe Insulation (3)	40	450
	6.7	Instrumentation and Controls (5)	230	5,200
			1,150	20,100

Table 73 (page 7 of 7)

		Direct Manual Field Labor MH 1000's	Balance of Plant Material $ 1000's
7.0	YARDWORK AND MISCELLANEOUS (1)		
7.1	Site Preparation and Improvements	38	10
-	includes soil testing; clearing and grubbing; rough grading; finish grading; landscaping		
7.2	Site Utilities	5	50
-	includes storm and sanitary sewers; nonprocess service water		
7.3	Roads and Railroads	27	750
-	include railroad spur; roads, walks, and parking areas		
7.4	Yard Fire Protection, Fences and Gates	52	600
7.5	Water Treatment Ponds	12	10
-	includes earthwork; compacted-clay lining; offsite pipeline		
7.6	Lab, Machine Shop and Office Equipment	1	280
		135	1,700

Table 74

MAJOR COMPONENT AND SUBSYSTEM CAPITAL COST SUMMARY
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED
1650 F

Major Component or Subsystem	No. of Units	Cost/Unit (FOB) M$	Component or Subsystem Costs (FOB) M$	BOP+ Materials M$	Site+ Labor (Direct + Indirect M$	Total Installed Cost M$
FUEL HANDLING & PREPARATION						
COAL AND SOLIDS HANDLING	3/2	-	32.23	11.98	5.67	49.88
PRIME CYCLE						
STEAM TURBINE-GENERATOR	1	25.00	25.00	0.10	2.34	27.44
PFB MODULES	4	3.67	14.68	1.06	6.05	21.79
ECONOMIZER	4	0.63	2.51	0.18	0.45	3.14
PRESSURIZING SYSTEM						
HOT GAS FILTERING	4	16.13	64.51	2.04	2.21	68.76
GAS TURBINE	4	6.41	25.62	0.10	0.89	26.61

The total costs using the AE's categories are presented in Table 75. The home office and fee of 15 percent is applied only to the BOP costs. A contingency of 20 percent of all prior costs is applied to cover expected costs not specifically included in the original estimating process. The total plant cost of $421 million represents $446/kW based on total generation, or $466/kW based on net station output.

A reconstruction of costs according to equipment function is presented in Table 76. Items 1 through 6 include everything in the preceding table. Item 7 adds the value of escalation and interest during the 5.5-year construction time. This item is 54.8 percent of the prior total. The result is a final plant cost of $693/kW of total generation or $723/kW of net station output.

Table 75

BALANCE OF PLANT CAPITAL COST BREAKDOWN
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED
1650 F

		Costs (Millions of Dollars)			
Categories*	Components	Direct Labor (1)	Indirect Field (2)	Materials (3)	Total
1.0 PFB STEAM GENERATORS & HOT GAS FILTERS	79.19	4.35	3.91	3.10	90.55
2.0 TURBINE GENERATORS	50.62	1.70	1.53	.20	54.05
3.0 PROCESS MECHANICAL EQUIPMENT	34.74	6.29	5.66	26.20	72.89
4.0 ELECTRICAL		9.52	8.57	11.00	29.09
5.0 CIVIL AND STRUCTURAL		9.99	8.99	11.20	30.18
6.0 PROCESS PIPING AND INSTRUMENTATION		13.51	12.16	20.10	45.77
7.0 YARDWORK AND MISCELLANEOUS		1.59	1.43	1.70	4.72
	164.55	46.95	42.25	73.50	327.25
		B.O.P. LABOR, MATERIALS & INDIRECTS 162.70 (SUM OF 1 + 2 + 3)			
		A/E HOME OFFICE & FEE @ 15%			24.41
		TOTAL PLANT COST			351.66
		CONTINGENCY @ 20%			70.33
		TOTAL CAPITAL COST			421.00

Table 76

PLANT CAPITAL COST ESTIMATE SUMMARY
(APPROXIMATE DISTRIBUTION)
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED
1650 F

		Major Components Materials M$	Balance Of Plant Materials M$	Site Labor (Direct & Indirect) M$	Total M$
1.0	LAND IMPROVEMENTS & STRUCTURES (LAND, PLANT AREA 108 ACRES) (LAND, 30-YEAR DISPOSAL 0 ACRES)		11.8	19.8	31.6
2.0	COAL HANDLING	32.2	12.0	5.7	49.9
3.0	PRIME CYCLE PLANT EQUIPMENT STEAM CYCLE/PRESSURIZED FLUIDIZED BED 738.6 MW_e PRESSURIZING GAS TURBINE 205.0 MW_e	132.3	33.4	39.6	205.4
4.0	BOTTOM CYCLE NOT APPLICABLE				
5.0	ELECTRICAL PLANT & INSTRUMENTATION	0	16.2	23.2	39.4
	SUBTOTAL	164.5	74.4	88.3	327.2
6.0	A-E SERVICE & CONTINGENCY				94.7
7.0	ESCALATION & INTEREST DURING CONSTRUCTION				231.2
				TOTAL M$	653.1
				PLANT OUTPUT MW_e	903.8
				TOTAL $/$kW_e$	722.8

6. NATURAL RESOURCES AND ENVIRONMENTAL INTRUSIONS

Natural Resources

Table 77 shows the natural resource requirements for the PFB plant. The consumption of coal for the PFB advanced steam power plant was 10 percent less than that for the AFB power plant, but the substitution of dolomite for limestone increased the sorbent requirement by 63 percent. The PFB requires 6 percent more pounds of material than the AFB per kilowatthour delivered when fuel and sorbent are totaled.

Water usage would be reduced for the PFB by 10 percent as compared to the AFB. This results from the procuction of gas turbine power that requires no coolant. Land area was comparable for the plants.

Environmental Intrusion

Table 78 enumerates the environmental intrusions of the PFB power plant. The sulfur emission is well below the mandated new Source Performance Standards for coal-fired boilers limit of 1.2 lb/MBtu of heat input; the nitrogen oxides are one-third of current limits. The major heat rejection is from the cooling tower. The stack heat rejection is greater than that for the AFB because the stack temperature was 300 F rather than 250 F.

The composition of the dry granular spent solids shows the effect of use of twice the ideal requirement for dolomite.

Trace Elements

To date experimental determination of trace element emissions from PFB combustion has not been made. Critical factors are the low bed temperature of 1650 F in the main beds and 2000 F in the CBC. These temperatures are below slagging temperature and are close to those found in the AFB. The discussion of trace elements for the AFB would be fully applicable to expectations for the PFB. Some differentiation should be expected when appropriate tests are made on each type.

One important differentiation is that the gases from the PFB are held at high temperature and then abruptly dropped to 912 F by expansion through the gas turbine followed by cooling to 300 F in the gas turbine economizer. Volatile trace elements with dewpoints above 300 F should condense out in the gas turbine and its economizer.

Table 77

NATURAL RESOURCE REQUIREMENTS
ADVANCED STEAM CYCLE - PRESSURIZED FLUIDIZED BED

	VALUE
SORBENT OR SEED, LB/kWh	
DOLOMITE	0.3715
COAL, LB/kWh	0.8076
WATER, TOTAL (GAL/kWh)	
COOLING	
EVAPORATION	0.405
BLOWDOWN	0.127
PLANT GENERAL USE	0.016
CONDENSATE MAKEUP	0
TOTAL LAND, ACRES/100 MW_e	
MAIN PLANT	12
DISPOSAL LAND	14

Table 78

ENVIRONMENTAL INTRUSION
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED

EMISSIONS	LB/MBtu INPUT	LB/kWh OUTPUT
SO_2	0.688	0.0060
NO_x	0.152*	0.0013
HC	-	-
CO	0.020	0.0002
PARTICULATES	0.100	0.0009
THERMAL POLLUTION		
HEAT REJECTED, COOLING TOWERS, Btu/kWh		3967
HEAT REJECTED, STACK, Btu/kWh		951
HEAT REJECTED, TOTAL, Btu/kWh		5300
WASTES	**LB/kWh**	**MLB/DAY**
SPENT SOLIDS CONGLOMERATE	0.3424	7.43
42% ASH COMPOUNDS		
26% CALCIUM SULFATE		
16% MAGNESIUM OXIDE		
13% UNREACTED LIME		
4% UNBURNED CARBON		
WATER DISCHARGE	1.19	25.9

*Based upon available data, EPA believes that the NO_x emission level will more typically be in the range of 0.1-0.4 LB/MBtu.

7. SUMMARY PERFORMANCE AND COST

Table 79 summarizes the system performance and cost for the PFB--Advanced Steam plant with 1650 F main beds. The overall energy efficiency of 39.2 percent is appreciably above the level of 35.8 percent for the AFB plant. However, the plant cost per kilowatt of $723 is $100 greater than the AFB value. It should be noted that major contributors to the PFB capital cost are the granular bed filters for cleaning the hot pressurized flue gas ($64.5 M uninstalled) and the high pressure solids handling system ($32.2 M uninstalled). The resulting increase in the capital portion of the cost of electricity (COE) is greater than the reduction in the fuel portion. The total result is an increase of 2 mills/kWh over the COE for the AFB.

The sensitivity of the cost of electricity to variation of major cost factors is presented in Table 80.

Table 79

SUMMARY PERFORMANCE AND COST
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED
1650 F

ITEM		
NET POWER PLANT OUTPUT (MW_e - 60Hz - 500 kV)		903.8
THERMODYNAMIC EFFICIENCY (%)		41.3
POWER PLANT EFFICIENCY (%)		39.2
OVERALL ENERGY EFFICIENCY (%)		39.2
COAL CONSUMPTION (LB/kWH)		0.808
TOTAL WASTES (LB/kWH)		0.343
PLANT CAPITAL COST ($ MILLION)		6653.3
PLANT CAPITAL COST ($\$/kW_e$)		722.9
COST OF ELECTRICITY, CAPACITY FACTOR = 0.65		
CAPITAL	(MILLS/kWH)	22.9
FUEL	(MILLS/kWH)	8.7
MAINTENANCE & OPERATION	(MILLS/kWH)	2.5
TOTAL	(MILLS/kWH)	34.1
ESTIMATED TIME OF CONSTRUCTION (YEARS)		5.5
APPROXIMATE DATE OF FIRST COMMERCIAL SERVICE		1987 - 1989

Table 80

COST OF ELECTRICITY (COE) SENSITIVITY
ADVANCED STEAM CYCLE-PRESSURIZED FLUIDIZED BED

	Base Capacity Factor 0.65	Fuel Cost Increase 50%	Labor Cost Increase 20%	Materials Increase 20%	Capacity Factor Change 0.5 & 0.8	
COE, CAPITAL	22.9	22.9	24.2	26.1	29.7	18.6
COE, FUEL	8.7	13.1	8.7	8.7	8.7	8.7
COE, O&M	2.5	2.5	2.5	2.5	2.6	2.4
TOTAL COE	34.1	38.4	35.5	37.3	41.0	29.7

8. PFB ALTERNATIVE #1 (1750 F)

In addition to the basic plant of Figure 27 with 1650 F beds, a PFB power plant with 1750 F main beds was evaluated. The intent was to minimize the changes from the basic plant concept so that the differences in performance and cost could be sharply defined. The PFB, gas turbines, hot gas filters, feedwater heaters and economizers, and steam turbine cycle were components subject to major variations.

The specifications for the PFB module retained the identical fuel rate and the identical air flow for combustion at the PFB as in the base case. The gas flow into the gas turbine was identical to the former case; only the inlet temperature was increased from 1600 F to 1700 F.

PFB Tower Costs

The PFB tower would increase from 13 ft diameter to 13.5 ft diameter. The height of 116 ft would be unchanged. The bed dimensions would increase from 8.5 ft on each side to 8.75 ft on each side. These changes would increase the cost of the PFB towers by $250,000 for the total plant.

Hot Gas Cleanup Costs

The ducting and cyclone separators for the hot gas flow would be unchanged. The granular bed filters must increase in size and cost to experience the same face velocity with the greater volume of gas flow. This ratio is 1.0485. As a result the granular bed filters and the air compressors that service them will have an added cost of $2,040,000. An audit of pressure loss from compressor outlet to gas turbine inlet shows that the 7.5 psi loss would then become 7.35 psi.

Gas Turbine Cost

The gas turbine flows and power were derived by scaling up the 1700 F gas turbine applicable to the PFB for the ECAS potassium topping cycle so as to match exactly the air required by the PFB in this instance. The gas turbine generation became 55.682 MW. The cost for the gas turbines was scaled at $125/kW to arrive at an added cost of $2,216,000 for the four gas turbines required by each plant. Table 81 gives a comparison of gas turbine characteristics. The configurations would have the same general dimensions as the base case. Pressures at each station would be identical, as would the air delivery temperature of 597 F to the PFB.

Steam Turbine-Generator Cost

A heat balance on the PFB towers, the Petrocarb cooler economizers, and the gas turbine economizers shows a total heat input to the steam cycle of 5984 MBtu/hr; the distribution is shown in Table 82.

Table 81

GAS TURBINE PERFORMANCE AND COST COMPARISON

PFB main bed temperature	1650 F	1750 F
Gas turbine inlet temperature	1600 F	1700 F
Compressor inlet air flow, lb/s	525.75	530.19
Air flow to PFB, lb/s	504.72	504.72
Gas flow back to turbine, lb/s	551.16	551.16
Exhaust gas flow, lb/s	571.13	576.58
Exhaust temperature	849.9 F	912.4 F
Generator output, MW	51.25	55.682
Unit cost, M$	6.41	6.74
Number per plant	4	4
Exhaust heat to 300 F, MBtu/hr	309.56	335.33

Table 82

PFB HEAT SOURCES FOR STEAM CYCLE

Source	MBtu/hr	
PFB main bed temperature	1650 F	1750 F
4 Petrocarb cooler economizers, E_x	22	22
4 Gas turbine economizers, E_y	1238	1341
4 PFB towers	4844	4621
Total heat to steam cycle	6105	5984
Total heat ratio to 1650 F case	1.0	0.980

For a 1750 F PFB cycle as described by Figure 27, the steam turbine output would become 723,960 kW. The difference of 14,673 kW less would reduce steam turbine-generator cost by $210,000 at the rate of $14.3/kW.

Gas Turbine Economizers

The gas turbine economizers will receive hotter gas and deliver hotter water. A heat balance was made to determine these resulting temperatures and to arrive at the log mean temperature difference for heat exchange. The heat exchanger cost was then proportioned directly with heat duty and inversely with log mean temperature difference. The assumption of the same heat transfer coefficient and a constant ratio of cost per unit area are justified for such a modest change in conditions. Table 83 details this evaluation.

The cost difference for the total plant for gas turbine economizers would be an increase of $145,000.

Balance-of-Plant Costs

BOP cost items may be affected by any of the following ratios:

Hot gas cleanup size ratio	1.0485
Steam turbine size ratio	0.980135
Total and net generation ratio	1.0034
Economizer size ratio	1.0581

The BOP items were adjusted by these ratios as shown in Table 84.

PFB Net Generation (1750 F)

A detailed auxiliary loss breakdown was made with no change in PFB auxiliary losses, steam turbine and heat rejection elements scaled by a 0.98 factor, and generation-related factors scaled by 1.0034 relative to losses shown in Table 31. The total loss was 39.87 as compared to 39.86 formerly. Net station output could then be evaluated as indicated in Table 85.

PFB Net Plant Cost (1750 F)

Table 86 summarizes the several changes in major component and BOP costs, applied fee, contingency, and other factors to arrive at the net station dollars per kilowatt.

Cost of Electricity Comparison

Table 87 compares the COE for the two cases. The efficiency, coal consumption, and fuel cost of electricity will be virtually the same. The major change was due to increased capital cost.

Table 83

ECONOMIZER DESIGN AND COST BASIS

Bed temperature	1650 F	1750 F
Heat duty, MBtu/hr	309.56	335.25
Gas T in/T out	865 F/300 F	912.4 F/300 F
Water T in/T out	537 F/250 F	559.2 F/253.5 F
Difference in temperatures	328 F/50 F	353.2 F/46.5 F
Log means temperature difference	147.79 F	151.26 F
Cost per unit, M$	0.627	0.66346

Table 84

BOP ADJUSTMENTS FOR 1750 PFB FROM 1650 PFB BASE CASE

	BOP Items	Changes		Factor
		MH 1000's	Mat. $1000's	
1.3	Hot gas cleanup (a)	+1.84	+ 4.85	1.0485
	(b)	+2.96	+94.09	1.0485
3.2	Main circulating pumps	-	-16.49	0.9801
3.4	Main condensers	-0.54	-47.08	0.9801
3.5	Heaters, Exchangers	-	-28.80	0.9801
3.12	Cooling towers	-1.13	-48.67	0.9801
4.0	Electrical	+2.73	+37.16	1.0034
5.4	Cooling tower basins	-1.99	-30.00	0.9801
6.1	Steam and feedwater piping	-0.99	-47.68	0.9801
6.3	Other large pipes	-3.87	-66.55	0.9801
	Total difference in MH 1000's	-1		
	Total difference BOP Mat		-149	
	Direct labor at 11.75 $/hr		- 12	
	Indirect labor at 10.58 $/hr		- 10	
	Total BOP change		-171	
	Former BOP cost		162 700	
	New BOP cost		162 529	

Table 85

POWER GENERATED BY PFB POWER PLANTS

	Power Generated at 2 Main Bed Temperatures (MW)	
	1650 F	1750 F
Gas turbine generation	205.0	222.7
Steam turbine generation	738.6	724.0
Gross generation	943.6	946.7
Auxiliary power loss	39.9	39.9
Net station output	903.8	906.8

Table 86

SUMMARY COSTS FOR 1750 F PFB

Item Changed	Change, M$
Balance-of-plant cost	- 0.17
Steam turbine generator	- 0.21
Gas turbine generators	+ 2.216
PFB towers	+ 0.25
Hot gas filters	+ 2.04
Gas turbine economizers	+ 0.145
Subtotal, all changes	+ 4.25
1650 F Case total	+327.25
1750 F Case total	331.5
AE home office & fee @ 0.15 x 162.53	24.4
Total plant cost	355.9
Contingency at 20%	71.2
Total capital cost	427.1
Escalation & interest during construction	234.0
Total expenditure for plant	661.1 M$
Plant net output	906.8 MW
Specific cost	729 $/kW

Table 87

COMPARISON OF COST OF ELECTRICITY - PFB

Main bed temperature	1650 F	1750 F
Plant capital cost, $/kW	723	729
Overall energy efficiency, %	39.2	39.3
Cost of electricity, mills/kWh		
Capital	22.9	23.1
Fuel	8.7	8.7
Operation & maintenance	2.5	2.5
Total	34.1	34.3

Based on 5.5 years to construct; 0.65 capacity factor.

9. PFB ALTERNATIVE #2-HIGH EFFICIENCY (1750 F)

A greater efficiency may be gained from the PFB cycle if the steam turbine cycle has high-temperature feedwater heaters that operate on part of the feedwater flow. The balance of the flow would be heated by a gas feed heater (GFH) which is truly the low-temperature portion of the gas turbine economizer. Then the total feedwater flow would enter the high-temperature portion of the gas turbine economizer. This arrangement is identical to that used for the ECAS potassium topping steam PFB and gas turbine cycle. The economizers must have increased surface area and cost as a result of their lowered mean effective temperature difference. The total heat available to the steam cycle is unchanged. The PFB would have altered proportions of heat exchange surfaces because of increased feedwater temperature of 640 F. The PFB configuration, size, and cost are not expected to differ from the 1750 F case discussed previously. Major changes are found in the economizers, the steam turbine cycle, and parts of the balance of plant. These changes are most readily understood by examining the steam turbine cycle first and then the gas turbine economizers.

Steam Turbine Cycle and Heat Balance

The steam turbine heat balance presented in Figure 37 is more nearly like the AFB turbine cycle than it is like the PFB turbine cycle of Figures 26, 27, and 31. The feedwater flow is split after the third low-temperature heater. Four high-pressure feedwater heaters pass 56.5 percent of the total feed-water flow. The Petrocarb compressor cooler (PCC) heats 1.6 percent of the total feedwater flow. The gas feedwater heater (GFH) cools the gas turbine exhaust from 560 F to 300 F while heating 41.9 percent of the total feedwater flow. All of these heaters deliver feedwater at 505 F. The total feedwater flow then passes through the gas turbine economizer where the gas cools from 912.4 F to 560 F as the feedwater is heated from 505 F to 640 F. The distribution of feedwater flow and heat duty are detailed in Table 88.

The increase in steam turbine output results in an increased component cost of $22,000 at $14.28/kW.

The cost of the feedheater train must be derived from the AFB steam cycle, which was similar. It was determined that feed-heater surface area varied linearly with heat duty for both high-pressure and low-pressure units. The heat duty for the seven feedwater heaters using extraction steam in Figure 37 is 0.5534 of the heat duty for the AFB steam turbine cycle. The flows and duties of the low-pressure feedwater heaters of the steam cycle bear a ratio of 0.9027 to the AFB cycle. The cooling duty is a ratio of 0.945 to the base PFB steam turbine cycle. Other significant ratios were derived from the appropriate flows, powers, and heat duties of the steam cycles.

Gas Turbine Economizer Cost

Economizer size and cost were estimated on a preliminary basis by the Foster Wheeler Energy Company. When final values for heat duty and log

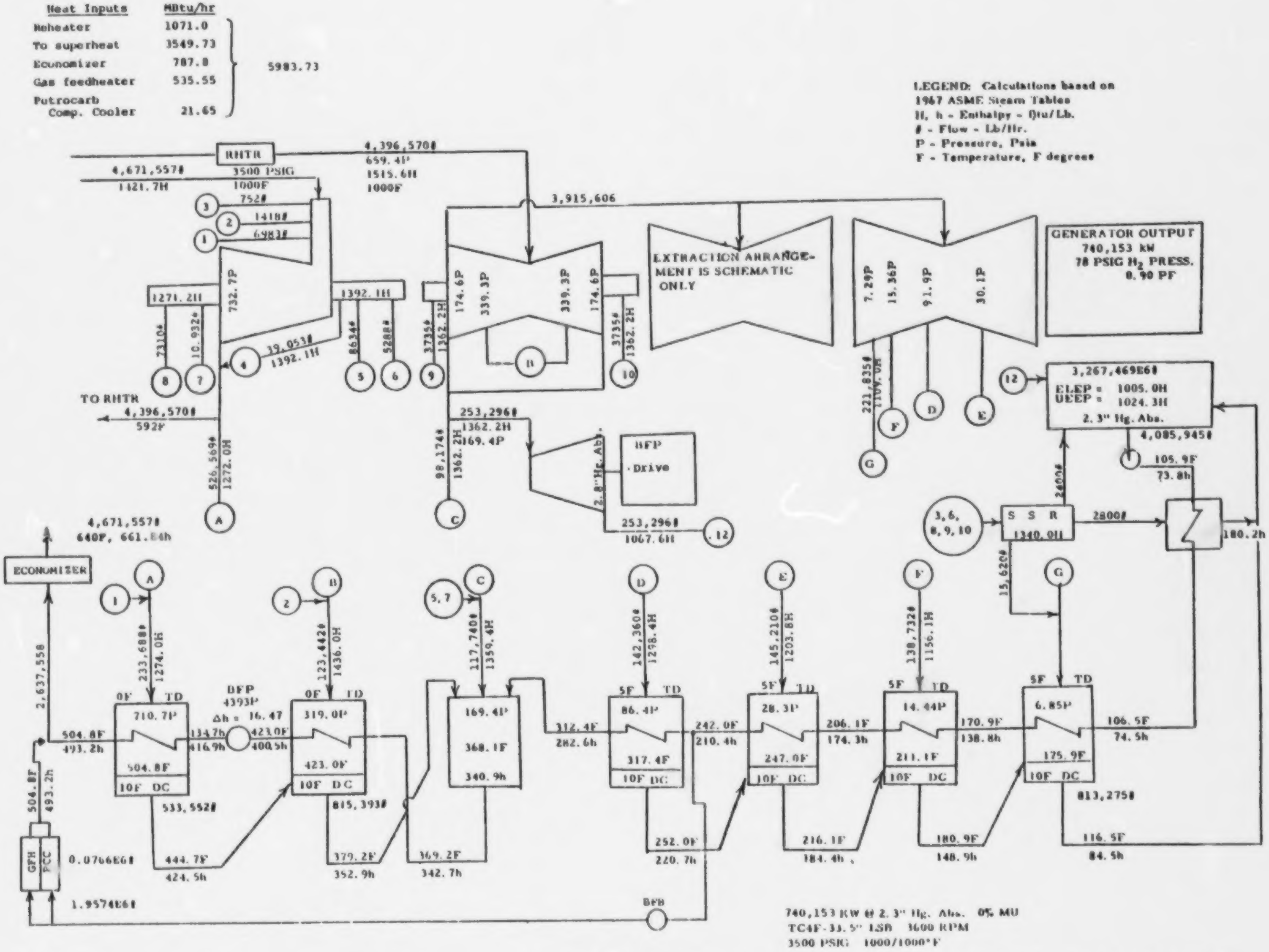

Heat Inputs MBtu/hr
Reheater 1071.0
To superheat 3549.73
Economizer 787.8
Gas feedheater 535.55
Putrocarb Comp. Cooler 21.65
5983.73
LEGEND: Calculations based on 1967 ASME Steam Tables
H, h - Enthalpy - Btu/Lb.
# - Flow - Lb/Hr.
P - Pressure, Psia
F - Temperature, F degrees
RHTR
4,671,557#
1421.7H
3500 PSIG
1000F
752#
1418#
6983#
4,396,570#
659.4P
1515.6H
1000F
3,915,606
732.7P
1271.2H
7310#
10,932#
39,053#
1392.1H
8634#
5288#
TO RHTR
4,396,570#
592F
526,569#
1272.0H
174.6P
339.3P
3735#
1362.2H
253,296#
1362.2H
169.4P
98,174#
1362.2H
BFP
Drive
2.8" Hg. Abs.
253,296#
1067.6H
EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY
7.29P
15.36P
91.9P
30.1P
221,835#
1109.0H
GENERATOR OUTPUT
740,153 kW
78 PSIG H2 PRESS.
0.90 PF
3,267,469E6#
ELEP = 1005.0H
UEEP = 1024.3H
2.3" Hg. Abs.
4,085,945#
105.9F
73.8h
2400#
2800#
S S R
1340.0H
15,620#
180.2h
4,671,557#
640F, 661.8h
ECONOMIZER
2,637,558
233,688#
1274.0H
0F TD
710.7P
504.8F
10F DC
504.8F
493.2h
533,552#
444.7F
424.5h
BFP
4393P
Δh = 16.47
434.7h
416.9h
423.0F
400.5h
123,442#
1436.0H
319.0P
423.0F
815,393#
379.2F
352.9h
117,740#
1359.4H
169.4P
368.1F
340.9h
369.2F
342.7h
312.4F
282.6h
142,360#
1298.4H
5F TD
86.4P
317.4F
252.0F
220.7h
242.0F
210.4h
145,210#
1203.8H
28.3P
247.0F
216.1F
184.4h
206.1F
174.3h
138,732#
1156.1H
14.44P
211.1F
180.9F
148.9h
170.9F
138.8h
6.85P
175.9F
813,275#
116.5F
84.5h
106.5F
74.5h
GFH
PCC
504.8F
493.2h
0.0766E6#
1.9574E6#
BFB
740,153 KW @ 2.3" Hg. Abs. 0% MU
TC4F-33.5" LSB 3600 RPM
3500 PSIG 1000/1000°F

Figure 37. High Efficiency 1750 F PFB Plant Steam Turbine Cycle Heat Balance

Table 88

HEATING DUTY FOR HIGH EFFICIENCY PFB PLANT STEAM CYCLE

Heat Exchanger	Heat Duty (MBtu/hr)	Flow (% of feed)
PFB to reheater	1071.0	94.1
PFB to superheat	3549.73	100.0
Gas turbine economizer	787.8	100.0
Gas turbine gas feed heater	535.55	41.90
Petrocarb compressor cooler	21.65	1.64
Steam turbine high-pressure feed heaters	-	56.46
Total heat to steam cycle	5983.73	-

mean temperature difference (LMTD) were available, the preliminary size and cost were scaled up or down appropriately, as shown in Table 89.

The plant economizer component cost difference would be $4.41 million which is four times the per unit difference of Table 4.2-29. The erection man-hours and BOP materials related to the economizers were scaled from the 1650 F PFB case using the total heat exchange surface area ratio of 2.58 as the scaling factor.

Balance of Plant Adjustments

BOP cost items were proportioned to comparable heat duty, flow rate, or power level for the 1650 F PFB or the 1550 F AFB as was deemed most appropriate. The comparison source, AFB or PFB, and the ratio used are indicated in Table 90 along with the changes in man-hours of direct labor and materials cost. Item 6.3, "Other large pipe," was scaled to the steam turbine cycle flows after the reheat turbine at pressure levels below 200 psia. Item 3.5, "Heaters, exchangers; Economizer erection," was subdivided into economizer-related costs, and steam turbine cycle steam-heated feedwater costs. The scaling factor for the latter was 0.553 based on the ratio of the heat duty of the feedheater trains.

Auxiliary Loss and Net Generation

The auxiliary losses of Table 66 were reapportioned using the same basic ratios as were used for the BOP adjustments. Since all ratios must be referred to the 1650 F PFB case and not to an AFB, items related to flows or condenser heat duty in the low-pressure portion of the plant used the ratio 0.945. The furnace items have been grouped in Table 91 since they are identical to the values of Table 66. The closeness of the final results is due to the offsetting effects of the many changes.

The net generation and efficiency improvement shown in Table 92 result from the increased steam turbine output resulting from the more elaborate feedwater heating system.

Net Plant Cost

Table 93 summarizes the several changes in major component and BOP costs. The fee and contingency and escalation and interest during construction are added to find the total expenditure for the plant. Division by the net station output gives the cost of $728/kW.

Cost of Electricity Comparison

Table 94 summarizes the effect on the cost of electricity for the several alternatives of PFB power plants. The 1750 F cases entail greater cost for the gas turbine and the hot gas filters. The output change is minimal for

Table 89

PFB GAS TURBINE ECONOMIZERS COST BASIS

Heat Exchanger	Heat Duty (MBtu/hr)	LMTD (°F)	Area (ft^2)	Cost (M$)
1650 F PFB economizer	309.6	147.8	179,326	0.627
1750 F PFB economizer preliminary	197.5	145.3	135,946	1.724
GFH preliminary	138.8	135.8	304,357	
1750 F PFB economizer	197.0	57.0	145,080	1.730
GFH final	138.4	58.4	296,230	

Table 90

BOP ADJUSTMENTS FOR 1750 F PFB HIGH EFFICIENCY PLANT FROM 1650 F PFB BASE CASE

Source		Item	Ratio	Labor (MH 1000's)	Material ($ 1000's)
PFB	1.3	Hot gas cleanup	1.0485 (a)	+ 1.84	+ 4.85
			(b)	+ 2.96	+ 94.09
AFB	3.1	Boiler feedpumps	0.786	-	+ 100
AFB	3.2	Main circulating pumps	0.903	-	- 117
AFB	3.4	Main condenser	0.903	- 3	- 95
AFB	3.5	Heaters, exchangers	0.553 (Part only)	-	- 22
PFB	3.12	Cooling towers	0.945	- 3	- 134
PFB	5.4	Cooling tower basins	0.945	- 5.5	- 83
PFB	4.0	Electrical	1.020	+16.5	+ 224
PFB	6.1	Steam & feed piping	1.091	+ 4.6	+ 217
PFB	6.3	Other large pipe	0.945	-10.7	- 184
PFB	6.5	Economizer erection	2.58 (Part only)	+31.6	+ 284.4
		Total difference, MH 1000's		+35.3	
		Total difference, BOP materials			+ 289
		Direct labor at $11.75/hr			+ 415
		Indirect labor at $10.58/hr of direct labor			+ 373
		Total BOP change from 1650 F to 1750 F, high efficiency			+ 1,078
		Former BOP cost			162,700
		New BOP cost, 1750 PFB, high efficiency			163,778

Table 91

ADVANCED STEAM--PRESSURIZED FLUIDIZED BEDS

Plant Configuration	Auxiliary Loads at 3 Main Bed Temperatures (MW) 1650 F Base	1750 F Base	1750 F High eff
Furnace auxiliaries	10.39	10.39	10.39
Solids handling	2.17	2.17	2.17
Steam turbine auxiliaries	2.37	2.32	2.37
Gas turbine auxiliaries	2.16	2.35	2.35
Pumps			
Condensate	0.95	0.93	0.90
Circulating water	4.40	4.31	4.16
Service water	0.89	0.89	0.89
Intake water	0.94	0.92	0.88
"Hotel" loads	8.34	8.37	8.51
Cooling tower fans	2.53	2.48	2.39
Transformer loss	4.72	4.73	4.82
Total auxiliary power	39.86	39.87	39.83

Table 92

POWER GENERATED BY PFB POWER PLANTS--SUMMARY

Plant Configuration	Power Generated at 3 Main PFB Bed Temperatures (MW) 1650 F Base	 1750 F Base	 1750 F High eff
Gas turbine generation	205.0	222.7	222.7
Steam turbine generation	738.6	724.0	740.2
Gross generation	943.6	946.7	962.9
Auxiliary power consumption	39.9	39.9	39.8
Net station output	903.8	906.8	923.1
Overall energy efficiency	39.2%	39.3%	40.0%

Table 93

SUMMARY COSTS FOR 1750 F PFB HIGH EFFICIENCY PLANT

Item Changed	Change (M$)
Balance of plant cost	+1.078
Steam turbine-generators	+0.022
Gas turbine-generators	2.216
PFB towers	.25
Hot gas filters	2.04
Gas turbine economizers	4.41
Subtotal all changes	10.02
1650 F case total	327.25
1750 F high efficiency total	337.3
AE office and fee @ 0.15 x 163.8	24.6
Total plant cost without contingency	361.8
Contingency at 20%	72.4
Total capital cost	434.2
Escalation and interest during construction	237.9
Total expenditure for plant	672.1 M$
Plant net output	923 MW
Specific cost	728 $/kW

Table 94

COMPARISON OF COST OF ELECTRICITY FOR PFB PLANT ALTERNATIVES

PFB Plant Configuration	Cost of Electricity at 3 Main Bed Temperatures 1650 F Base	1750 F Base	1750 F High eff
Plant capital cost $\$kW_e$	723	729	728
Overall energy efficiency	39.2	39.3	40.0
Cost of electricity, mills/kWh			
Capital	22.9	23.1	23.0
Fuel	8.7	8.7	8.6
Operation and maintenance	2.5	2.5	2.5
Total	34.1	34.3	34.1

Basis: 5.5 Years to Construct; 0.65 Capacity Factor a fixed steam turbine cycle configuration. The more complex plant cycle with a gas feedheater operating in parallel with steam feedheaters gains in efficiency and reduces the total cost of electricity at 1750 F. A similar finding would be expected at 1650 F. The differences in cost of electricity are small as is the 2-percent savings in fuel at the extreme. Other factors should dictate the plant configuration and design specifications when the impact of appreciable changes in temperature level and complexity bring such small changes in efficiency and cost of electricity.

E. PLANT CONCEPTUAL DESIGN AND BALANCE-OF-PLANT COST

1. INTRODUCTION

The primary objective of the balance of plant portion was the achievement of a consistent level of detail and the development of compatible capital cost projections. In order to achieve this objective, similar subsystems were employed for the common cycle elements and consistent groundrules and costing methodology were used.

In an attempt to itemize balance-of-plant capital costs, symmetrical arrangements were used for the major components. This permitted employment of the shortest runs of high-temperature piping. To the greatest possible extent, existing technology was utilized for the common subsystems.

The groundrule criterion which had a significant influence on the plant layout was a requirement for a 60 day on-site storage of fuel. The fuel was assumed to be delivered to the plant site by unit train.

Off-site solid waste disposal was assumed with removal from the plant site by train or track. A 15-day interim on-site storage was provided for the solid waste.

The "North River" was available for obtaining the plant makeup water supply. Waste water was treated before returning to the river for discharge. There was no thermal rejection into the river.

In most respects, the balance-of-plant requirements for the fluidized bed plant concepts are similar to those for conventional power plants. The balance-of-plant items which were considered were:

- Fuel storage and handling involves the receiving, storage, and delivery to the combustion system of coal and limestone additives.

- Equipment installation includes installation of the combustion and primary energy conversion equipment as well as erection of the entire plant facility.

- Thermal cycle heat rejection includes cooling towers, circulating water pumps, and piping.

- Plant enclosure includes buildings for plant administration, control, turbomachinery, and furnace systems. (The geographic location of the plants in this study necessitates enclosure of most of the plant equipment.)

- Electric energy output provisions include bus bar, switchgear, transformers, and wire to conduct the generated electric energy to the plant high voltage switchyard.

- Plant control includes instruments, recorders, computers, and all other equipment necessary to monitor and control the power plant.

- Site preparation includes excavation, roads, fences, and landscaping.

The variety of energy conversion systems included in this study resulted in many plant support subsystems which required definition and cost estimates. The subsystems unique to the individual energy conversion systems are described in each individual conversion system section and plant layout drawings, equipment lists and cost breakdowns are presented. The balance-of-plant subsystems which are common to several conversions systems are discussed in this section. These subsystems were appropriately scaled to adjust for difficult capacity requirements.

2. BALANCE-OF-PLANT SUBSYSTEMS

Coal and Sorbent Receiving, Handling, and Storage

All coal is delivered by unit trains to the plant. The plant coal-handling system must unload the trains, move the coal to outside storage piles, reclaim the coal from storage as needed by the plant, and deliver the reclaimed coal to hoppers at the combustor feed system. Coal storage capacity of each plant is 60 days at rated energy output.

For the AFB and PFB plants dolomite or limestone sorbent material is mixed and injected with the coal. Thus a receiving, storage, and handling system similar to that for coal is provided for this material. This also requires provision for 60-days of storage capacity.

Plant requirements that significantly influence the selection, sizing, and arrangement of equipment for receiving, handling, and storage of coal and solid sorbent material are the following:

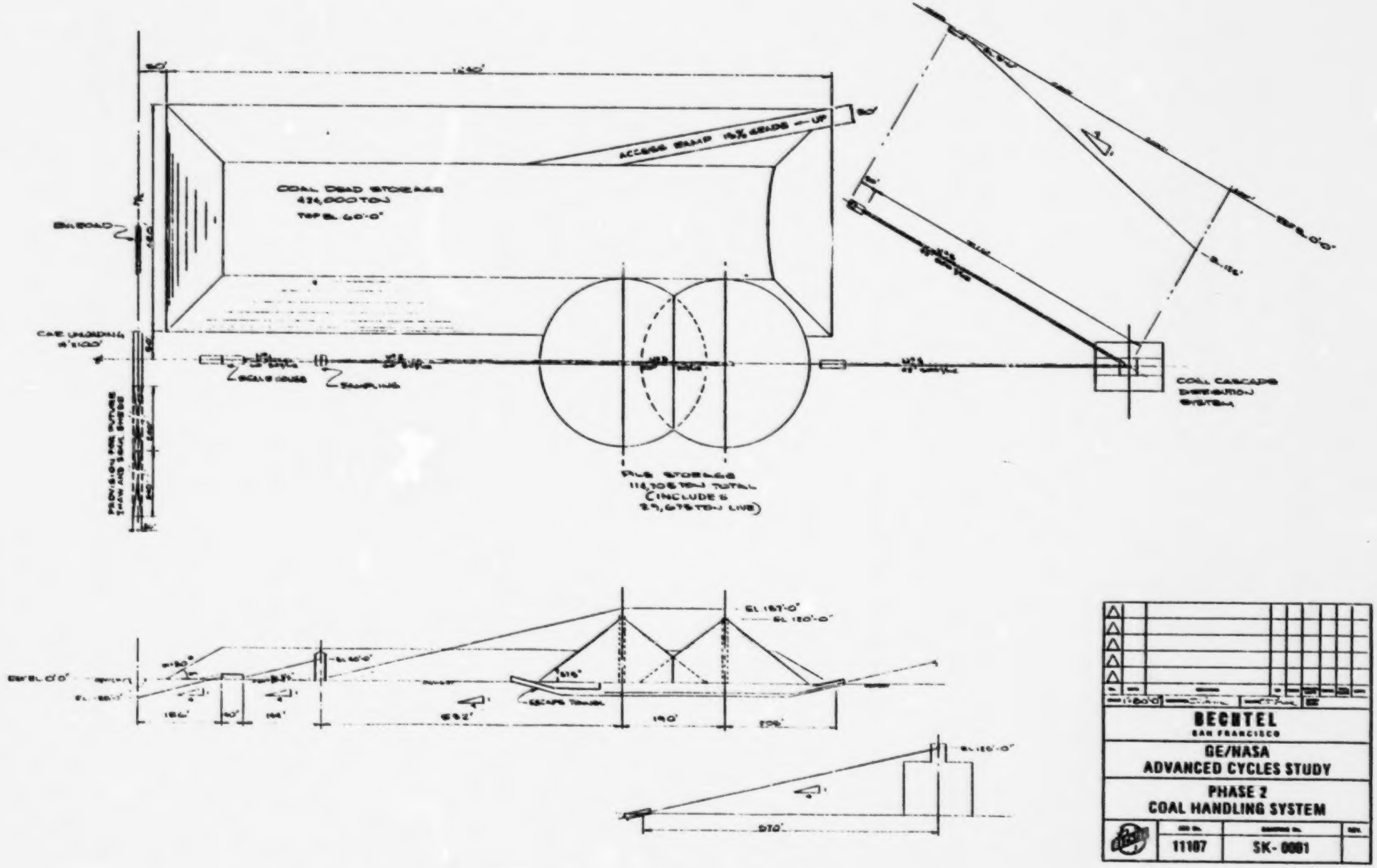
- Live storage of sufficient fuel to supply the plant for 3 days at rated capacity.
- Dormant storage of sufficient fuel to supply the plant for 60 days at rated capacity.
- Rail delivery by unit train of coal and/or sorbent material with motor truck access as an alternate.

Coal

Figure 38 shows the general arrangement of coal receiving, handling, and storage facilities for all plants. This concept includes two conical active storage coal piles and a 60-ft high dead storage.

Coal will be transported from the mine in unit trains consisting of bottom discharge cars. Cars will discharge the coal into under-track hoppers; the coal from these hoppers will be fed to two horizontal collecting belts for feeding the coal to the main 60-in., 3000 ton/hr belt conveyor. This high capacity belt will rapidly unload the unit train contents to the active storage piles. Train unloading time is less than four hours. To account for the coal received at the plant, the coal will be weighed in the scale house and representative samples of "as received" coal will be collected in the sampling station. The sampling station tower houses the coal sampling equipment, transfer hoppers, and drive equipment for the inclined conveyor to the active storage piles.

The two active storage conical piles are formed by discharging the coal into the lowering wells at each pile. The lowering well tubes also serve as support structures for the conveyor belts. Coal from the active storage is fed to a 500-ton/hr conveyor by hopper feeders under the coal pile. A tunnel has been provided for personnel emergency exit from the installation under the coal pile.



COAL DEAD STORAGE
424,000 TON
TOP EL 60'-0"
ACCESS RAMP 15% GRADE — UP
1,240'
RAILROAD
CAR UNLOADING
PROVISION FOR FUTURE THAW AND SAMPLING SHEDS
SCALE HOUSE
SAMPLING
PILE STORAGE
116,705 TON TOTAL
(INCLUDES 29,675 TON LIVE)
COAL CASCADE DISTRIBUTION SYSTEM
EL 137'-0"
EL 120'-0"
EL 60'-0"
ESCAPE TUNNEL
190'
EL 120'-0"
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED CYCLES STUDY
PHASE 2
COAL HANDLING SYSTEM
11107
SK-0001

Figure 38. Coal-Handling System (Bechtel)

Dead storage of coal for each of the plants is based on the 60-day full-load requirement; and the active storage is for three days, without the need for bulldozing. In an emergency, coal can be bulldozed from the dead storage pile and transported by the emergency reclaim conveyor to meet the plant requirements.

In anticipation of probable future needs to thaw frozen incoming coal, space has been provided for the thaw and soak sheds for railroad cars. Coal lump crushers have been provided between the active and the emergency coal reclaim systems and the boiler plant, to break up the oversize frozen coal. It is expected that coal falling on the grizzly will also aid in breaking up the frozen coal lumps.

The coal handling, storage and processing capacities as required for each plant are included in the discussion of each plant.

Sorbent Material

The sorbent material will be delivered in bottom discharge railroad cars. The general arrangement of the limestone or dolomite receiving, handling, and storage equipment is similar to the corresponding coal systems.

Sorbent material is unloaded into the same under-track hoppers as the coal, and discharged to the main coal conveyor belt for transport up to the first lowering well structure of the coal pile. At this point the sorbent material is diverted to the 3000-ton/hr conveyor supplying the lowering well of the active sorbent material storage pile. Sorbent material is weighed in the scale house and samples obtained using the coal sampling equipment, after taking necessary precautions not to contaminate the sample with coal remains.

Sorbent material from the active pile is transported to the distribution bin by a 36-in., 125-ton/hr conveyor. The dead storage is adjacent to the active storage and is built up by moving material from the active storage with mobile equipment such as a bulldozer or a scraper.

Water Treatment and Disposal

Water for each plant will be withdrawn from the North River (Middletown, U.S.A.) and treated for distribution to the plant water systems. It is assumed that the river water is of moderate hardness, is somewhat turbid, and has a total dissolved solids (TDS) level of about 250 mg/l. A raw water storage pond is provided to settle out suspended solids and to serve as a surge volume during periods of high turbidity or low flow in the river.

The river intake pumps supply water to maintain a sufficient level in the storage pond for about 3 days' makeup requirements. Suspended solids in the river water settle out in the pond, which will be dredged periodically to remove accumulated silt.

Water is treated to meet the various water use quality requirements. Wastewaters are treated to meet EPA new source standards for the steam electric power generating category. There will be no wastewater discharge from ash handling.

Water Treatment

Figure 39 presents a generalized water treatment flow diagram. Raw water from the storage pond is used directly for water makeup where applicable. Water is pumped from the pond into the supply header and distributed to the plant water systems.

Makeup to the recirculating cooling water system replaces evaporation, drift, and blowdown losses. The recirculating water is treated with sulfuric acid for scale control and, periodically, with chlorine for control of fouling organisms.

Raw water used in the potable, utility, and boiler feedwater systems (general plant use) is cold lime softened and filtered. A storage tank provides an assured source of fire water in the process area. Sludges from softening and filtration are pumped to the sludge handling system.

The potable water supply is disinfected with sodium hypochlorite using a conventional contact system. Utility water is usually used without further treatment for such purposes as bearing, gland and sample cooling, fire extinguishing water, and general washdowns. Special uses include fuel gas cleanup (combined cycle gas turbine-air cooled) and liquid fuel washing and NO_x suppression (combined cycle gas turbine-water cooled).

Boiler feedwater is demineralized in an ion-exchange system consisting of parallel trains, each having a cation (H) bed, an anion (OH) bed, and a mixed resin bed in series. The ion-exchange beds are regenerated periodically with sulfuric acid and caustic. Spent regenerates and rinse waters are routed to waste treatment facilities. Demineralized water from the storage tank and polished condensate are deaerated before being pumped to the boiler drum. Chemicals are added to the water in the deaerator to control scaling and corrosion in the boiler system (ammonia, hydrazine, and trisodium phosphate). Water treatment equipment, except for the storage ponds, is treated as a package unit for cost estimating.

Wastewater Treatment and Disposal

In general, wastewater from various sources are segregated and treated to meet the applicable discharge limitations. Treated wastewaters are then combined in a final holding pond for gravity discharge to the North River downstream of the plant intake system. Figure 39 illustrates generalized wastewater treatment systems, some or all of which are applicable to each power plant cycle.

Wastewaters are treated to meet the EPA new source standards for the steam electric power generating category.

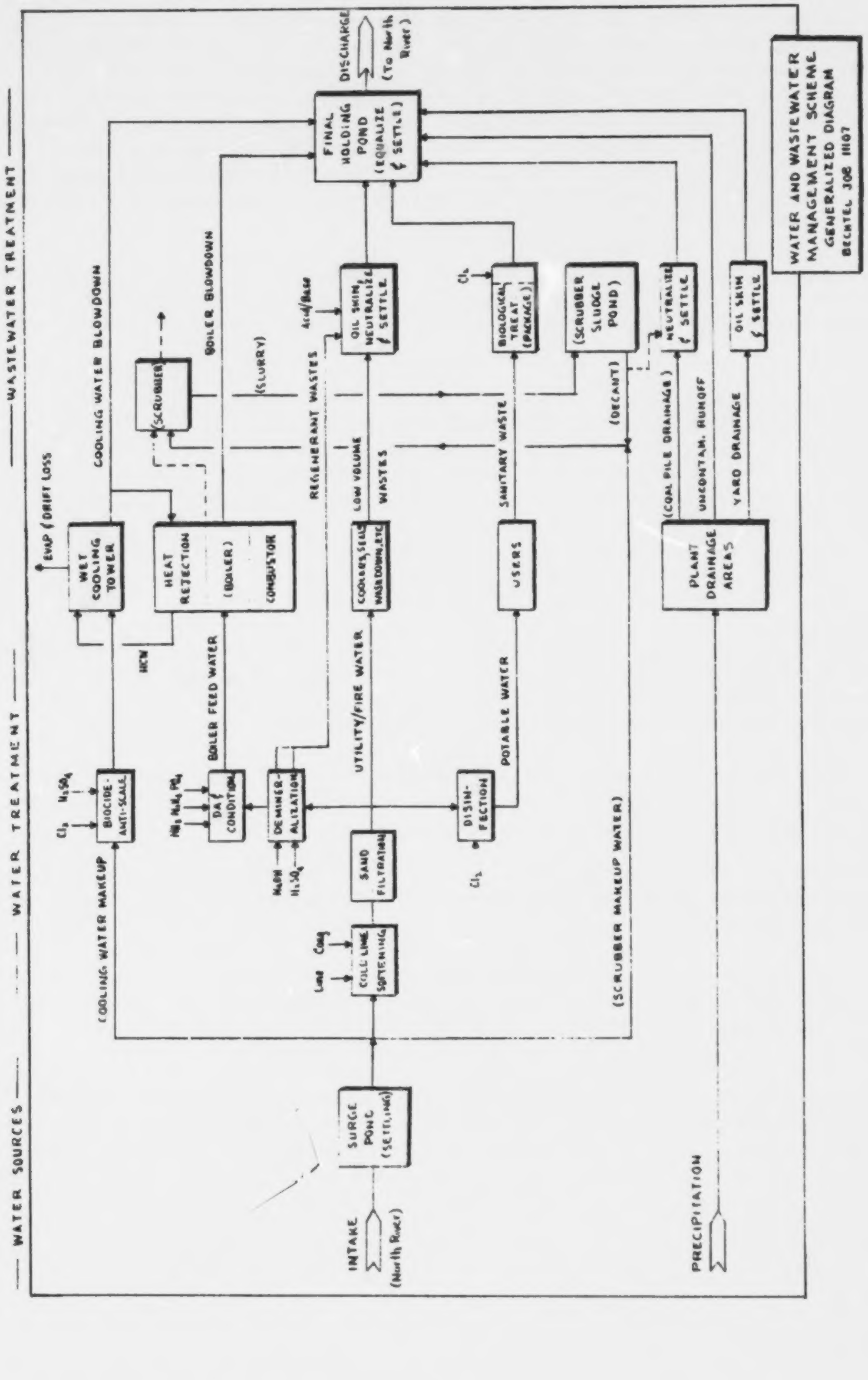

WATER SOURCES
WATER TREATMENT
WASTEWATER TREATMENT
INTAKE
(North River)
SURGE POND (SETTLING)
PRECIPITATION
COOLING WATER MAKEUP
Lime
Coag
COLD LIME SOFTENING
SAND FILTRATION
Cl₂
H₂SO₄
BIOCIDE-ANTI-SCALE
NH₃ N₂H₄ PO₄
DA & CONDITION
NaOH
H₂SO₄
DEMINER-ALIZATION
Cl₂
DISIN-FECTION
BOILER FEED WATER
UTILITY/FIRE WATER
POTABLE WATER
(SCRUBBER MAKEUP WATER)
HCW
WET COOLING TOWER
EVAP & DRIFT LOSS
HEAT REJECTION
(BOILER)
COMBUSTOR
COOLERS, SEALS WASHDOWN, ETC
USERS
PLANT DRAINAGE AREAS
COOLING WATER BLOWDOWN
SCRUBBER
BOILER BLOWDOWN
(SLURRY)
REGENERANT WASTES
LOW VOLUME WASTES
SANITARY WASTE
(DECANT)
(COAL PILE DRAINAGE)
UNCONTAM. RUNOFF
YARD DRAINAGE
Acid/Base
OIL SKIM, NEUTRALIZE & SETTLE
Cl₂
BIOLOGICAL TREAT (PACKAGE)
(SCRUBBER SLUDGE POND)
NEUTRALIZE & SETTLE
OIL SKIM & SETTLE
FINAL HOLDING POND (EQUALIZE & SETTLE)
DISCHARGE
(To North River)
WATER AND WASTEWATER MANAGEMENT SCHEME
GENERALIZED DIAGRAM
BECHTEL JOB 11107

Figure 39. Water and Wastewater Management

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Cooling Tower Blowdown. Corrosion resistant materials are used in the recirculating water system to eliminate the need for corrosion inhibitors. Blowdown is taken from the cool side of the recirculating water system to meet the thermal discharge requirement. The pH of the recirculating water is maintained above 6.0 so that no adjustment is needed. The available chlorine specification limit in the blowdown stream is met by careful control of the residual chlorine in the recirculating water and by temporarily shutting off the blowdown if the chlorine residual is too high. The blowdown, therefore, is discharged directly to the final effluent pond without any need for treatment. The final holding pond provides holding time for decay of any residual chlorine.

Boiler Blowdown. Blowdown from the boiler drums is moderately alkaline and of very high quality, oil-free, and low in TDS and TSS. No treatment is needed other than blending this stream with other wastewaters to lower its pH before discharge.

Metal Cleaning Wastes. Wastewaters are generated periodically by routine maintenance cleaning of heat transfer surfaces and cleaning of miscellaneous equipment. Cleaning wastes, both acidic and basic, contain dissolved chemicals and metals. The wastes from cleanouts are collected in storage tanks and worked off at a low rate over several weeks in a reactor-clarifier system in which lime is used to maintain a moderately alkaline pH of 8.5-9.0. Metal hydroxides are precipitated and removed as an underflow sludge stream. Clarifier overflow is routed for final pH adjustment to the surge basin that accepts other process wastes.

Low Volume Wastes. Low volume wastes include demineralizer brines and rinses, lab end sample wastewaters, floor drainage, and other utility water blowdowns. These are collected in a surge pond, skimmed of oil, neutralized, and settled before discharge to the final holding pond.

Area Runoff. Yard drainage and runoff from material storage areas are collected in settling basins sized to impound the runoff from a worst case 10-year storm of 24-hr duration (4-in. rainfall assumed).

Provisions are included to neutralize the runoff prior to discharge to the final holding pond. Settled runoff is expected to meet the 50 mg/1 TSS discharge limitation.

Sanitary Wastewater. Sanitary wastewater is treated in a conventional extended aeration biological system to meet biochemical oxygen demand (BOD) and TSS discharge requirements. Treated effluent is disinfected with chlorine.

Final Holding Pond. This pond receives treated wastewater from all sources and provides about a 2-day holding capacity. Wastewater is discharged through a gravity line to the North River downstream of the intake pumphouse. Final effluent quality is expected to be:

pH	6.0-9.0
Temperature, K	294
TSS, mg/l	30
O & G, mg/l	15
Copper, mg/l	1
Iron, mg/l	1

C. SOLID WASTES HANDLING AND DISPOSAL

The various power plants produce a variety of solid waste residues that must be collected and removed from the combustion systems. These residues range from slag and fly ash from the direct coal-fired MHD system to the mixed ash and calcium sulfates from the fluid bed combustion systems. The nature of the collected residue is a function of the combustion system that generates the residue or of the equipment that separates the residue from a flow stream. Likewise the residue transport means employed in a plant design will be dependent on the combustion process and/or separation equipment.

Fluidized Bed Combustion Systems

The approach to collecting the fluidized bed combustion systems residues is to consider them as being dry and relatively cool for transport by covered conveyor belt to surge bins at the rail spur. These surge bins unload normally into covered rail cars, or alternatively into motor trucks, for residue removal off site for disposal. In order to allow for plant operation in event of temporary transportation disruptions, on-site residue storage silos are also provided near the rail spur. These storage silos are sized to hold up to 15 days of plant residue production at plant rated operating conditions. The silo storage system would be used intermittently and is not part of the active conveyor system that continuously removes solid residues from the plant's combustion system equipment.

Maintaining the fluidized bed residues in a dry condition while transporting to a final disposal area is most important. These residues are mixtures of ash, noncombusted particles from the feed coal and calcined lime. Should the mixture become wet, it will harden. Therefore, the fluidized bed residues must be kept dry until final disposal.

D. HEAT EXCHANGERS

Condenser

All steam condensers are sized to provide a condensing pressure of 2.3-in. Hga under standard day design conditions in which circulating water temperatures are 70.5 F at the condenser inlet and 100.5 F at the outlet. Tubes in all steam condensers are assumed to be 1-in. outside diameter BWG #18 a wall thickness of 0.049-in. Tubes are assumed to occupy 22.5 percent of the tube sheet cross-sectional area. The overall heat transfer coefficient for these condensers is assumed to be 600 Btu/hr ft^2°F.

Deaerating Heater and Tank

The deaerating feedwater heaters are assumed to have an overall heat transfer coefficient of 600 Btu/hr ft^2°F. The storage tank capacity is sized to contain five minutes of the total boiler feedwater flow.

Feedwater Heaters

Heat transfer tube surface requirements for closed feedwater heaters in the study are calculated by assuming an overall heat transfer coefficient of 600 Btu/hr ft^2°F.

E. PIPING

Pipe Sizing

Piping diameters were selected on the basis of given mass flow rates and velocities which are representatively selected from power plant design experience for the classes of flows under consideration. Approximate velocities assumed in the study for conventional flows are:

Fuel oil	5 ft/s
Service water	8 ft/s
Boiler feedwater	20 ft/s
Saturated steam	150 ft/s
Superheated steam	300 ft/s

Once the internal pipe diameter is determined, pipe wall thickness is calculated based upon the ANSI B 31.1 Power Piping Code for minimum wall thickness.

The allowable material stress, is taken from the ASME Code for pressure piping and depends on both the pipe material and the design temperature.

Pipe Materials

Following conventional steam-electric plant practice, pipe material is A106 carbon steel for water and steam lines under 850 F (for example, boiler feedwater, cold reheat, condensate, process water) and 1-1/4 chromium--1/2 molybdenum for steam lines from 850 F to 1100 F (for example, main steam and reheat). Mid-1975 costs for fabricated carbon steel and chrome-moly piping are estimated at $1.10/lb and $2.00/lb, respectively. Additional allowances for fittings, hangers and supports, installation labor operations, and insulation were developed from power plant construction cost reports and are included in the piping estimates.

For the PFB, hot gas piping is carbon steel with internal refractory lining. Refractories were selected on the basis of temperatures and fluid conditions at the hot surface. Double-layer linings are employed in very high temperature applications and use a high-temperature refractory at the hot surface backed up by a more highly insulating low-temperature refractory adjacent to the carbon steel shell. Characteristics of refractories used in hot gas piping are given in Table 95.

An internal liner of Incoloy 800 is included in the PFB gas turbine inlet piping to prevent refractory particles from entering the turbine gas path. The fabricated liner (usually 0.125 in. thick) is estimated at $16.00/lb.

As in the conventional piping estimates, additional allowances are included in the unconventional piping estimates for fittings, hangers and supports, installation labor operations, and anchors for refractory linings where applicable.

F. COOLING TOWERS AND CIRCULATING WATER SYSTEMS

All plants used cooling systems employing evaporative, mechanical draft cooling towers. This type of tower was selected because of its minimum capital cost features and its ease of application to a wide range of thermal load requirements by use of multiple tower cells operating in parallel.

The Middletown, U.S.A., site is near a river which can supply sufficient quantities of cooling water makeup as well as receive treated blowdown water. The following atmospheric conditions at Middletown have been used as the design conditions:

Wet bulb temperature - 51.5 F
Dry bulb temperature - 59 F
Relative Humidity - 60%

Design Conditions. To achieve an absolute pressure of 2.3 in. Hga in the steam condensers requires that the equilibrium condensing temperature be maintained at 105.85 F. This is the heat source design temperature for the cooling water system.

The heat sink design temperature is the design wet bulb temperature of 51.5 F. An approximate minimum cost cooling system is achieved by using the following working temperature differences for the cooling system components:

a. Terminal Temperature Difference (TTD) is the difference between steam condensing temperature and the hot cooling water temperature leaving the condenser. The TTD used was 5.35 F.

b. Range is the temperature difference between the hot cooling water to the cooling towers and the evaporatively cooled water in the cooling tower basins. The Range used was 30 F.

c. Approach is the temperature difference between cooling tower basin water and the ambient wet bulb temperature. The approach used was 19 F.

Table 95

REFRACTORY MATERIALS

Type	Max. Temp. at Hot Surface	Thermal Conductivity (Btu in /hr ft^2 °F)	Cost per Linear Ft
Brick	3300 F	5.3 @ 2500 F	$41.80
Castable	3300 F	5.5 @ 2500 F	41.00
Castable	2800 F	4.9 @ 2000 F	40.00
Brick	2600 F	2.8 @ 2000 F	11.20
Castable	2300 F	2.1 @ 1500 F	9.55
Brick	2000 F	2.1 @ 1500 F	8.60
Block*	1900 F	0.7 @ 1000 F	6.00
Castable	1800 F	1.7 @ 1000 F	7.00

*For second-layer, backup insulation use only

These temperature relationships for the cooling system are illustrated by the Figure 40.

Applying the Reference cooling tower design techniques with the above conditions of wet bulb temperature, range, and approach provides a tower unit rating factor (RF) of 1.473. Under these service conditions, large mechanical draft cooling tower cells are rated at a recommended 15,750 tower units (TU) per cell, and each cooling tower cell has a rated water flow capacity of 10,692 gpm.

The standard dimension of each cooling tower cell was 75 ft (6.97 m) wide by 36 ft long by 47 ft high. Each cell contains one circulating fan and motor of 150 fan horsepower which induces the air draft through the two opposite sides of the cell.

The heat dissipation capacity per cell is 1.6×10^8 Btu/hr-cell.

Fan motor power per cell, assuming 97.5 percent motor efficiency, is 115 kWe/cell.

Water consumption rate per cell consists of two components: (1) water evaporation to the atmosphere and (2) basin blowdown water to prevent an excess accumulation of dissolved solids in the cooling-water system. The water evaporation rate, based on prior experience, is approximately 2.1 percent of the rated water circulating rate. Water loss allowance for blowdown is 0.5 percent of the water circulating rate.

Water Consumption Allowance is therefore:

Evaporation	220 gpm/cell
Blowdown	53 gpm/cell
Total Consumption	273 gpm/cell

Circulating Water System Design

Circulating water systems serve to pump water from the cooling tower basins through condensers and other heat exchangers and back to the cooling towers. Water quantity is determined by each plant's requirements but is related linearly to the number of cooling tower cells required for each plant. Large diameter underground piping from the cooling towers to the pumps and on to the plant, as well as from the plant back to the cooling towers, is required to achieve a nominal water velocity in the piping system of 7 ft/s. This velocity minimizes the net cost of the circulating water system considering installed capital costs and ongoing pumping costs associated with velocity-sensitive line pressure losses.

Pump sizing for the circulating water systems is based on using a minimum of three pumps at one-third of plant water flow requirements. This use of parallel pumps ensures that in the event of a single pump failure, sufficient cooling water flow is available to permit near normal plant load adjustment followed by continued part load operation, if needed. The redundancy also facilitates pump and motor servicing. Circulating water

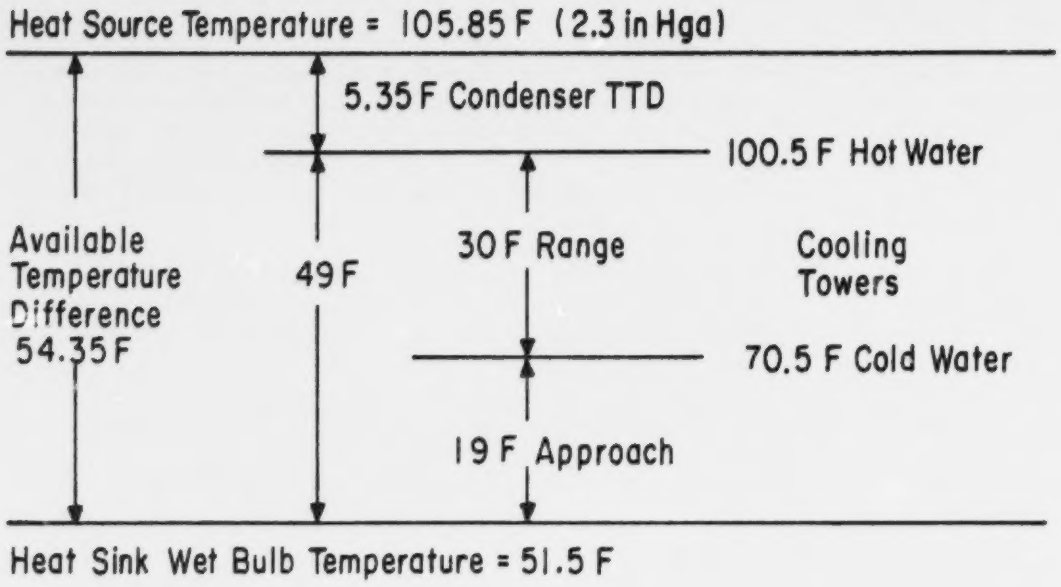
Heat Source Temperature = 105.85 F (2.3 in Hga)
5.35 F Condenser TTD
100.5 F Hot Water
Available Temperature Difference 54.35 F
49 F
30 F Range
Cooling Towers
70.5 F Cold Water
19 F Approach
Heat Sink Wet Bulb Temperature = 51.5 F

Figure 40. Cooling Tower Temperature Differences

system capacity is related to the number of cooling towers installed in each plant; thus pump and pipe design parameters are defined per unit cooling tower cell. Each cooling tower cell requires a nominal water flow of 10,692 gpm. Pump motor power required per cell is based on these assumptions:

- 15 percent additional capacity allowance
- 80 percent pump efficiency
- 97.5 percent motor efficiency
- 62 ft of total pressure head

These criteria result in per cell pump power requirements 240 hp/cell and a motor capacity of 184 kW/cell.

G. EXHAUST STACKS

The exhaust stacks were assumed to be concrete, tapered at 4 percent with an acid resistant steel liner and stainless steel rain hood. The liner is insulated on the outer surface. The top 25 feet of the liner and the rain hood are stainless steel.

Stack foundations are site sensitive depending on local wind loading, soil conditions, and so on. For cost estimating purposes, all stack foundations are assumed to be concrete pads 8 ft deep, which exceed the stack base diameter by 40 feet.

Stack liner diameters are sized by assuming a gas velocity of 90 ft/s at the exit of all stacks. Stack heights are determined as a function of tons per day of sulfur dioxide emission per stack. The sizing of stack heights depends on specific site conditions including prevailing weather patterns, soil conditions, composition of emissions, and so on.

H. AUXILIARY LOADS

For each plant two basic types of electrical loads are involved. The first type is associated with major power cycle equipment and is generated by the equipment suppliers. These loads include furnace auxiliaries and gas and/or steam turbine auxiliaries.

The second type of electrical load includes all specific equipment loads and general plant loads associated with balance-of-plant systems. Electrical loads included in this category and estimating methods for these loads are:

1. Fan loads, based on required flow rates and pressure differences. The fan efficiency range is 75 to 82 percent, and the motor efficiency is 90 percent.

2. Pump loads, also based on required flow rates and pressure differences. The pump efficiency range is 75 to 82 percent and the motor efficiency is 90 percent.

I. ELECTRICAL SYSTEMS

Systems Description

The electrical system for each of the plants is defined by the study groundrules to include all electrical equipment and associated bulk materials for both in-plant auxiliary loads and plant output power up to the 500 kV transmission voltage terminals of the main power transformers. Switchyards are excluded from the plant scope.

The electrical system concepts are illustrated in the form of single-line diagrams included with the drawings for each energy conversion system. Specifications for all significant transformers (for example, main, startup, auxiliary, station service) and the standby diesel generator sets are given in the equipment list for each of these systems.

Transformers

The main transformer capacity provided for each plant is based on the total power generating capacity of the station less the in-plant auxiliary load. Two one-half capacity transformers are provided.

The capacities of the startup and auxiliary transformers are based on the expected in-plant startup and operating loads, respectively. Station service transformers are provided as required so that 13.8 kV power is supplied to motors greater than 10,000 hp (7457 kWe), 4.16 kV power is supplied to motors between 250 hp (186 kWe), and 10,000 hp (7457 kWe), and 840 V power is supplied to motors less than 250 hp (186 kWe).

Standby Power

Uninterruptible electric power systems for critical a-c and d-c loads are provided for each plant. A 1,000-kWe diesel generator supplies emergency a-c power to a 480-V critical equipment bus. A 125-V d-c system consisting of storage batteries and battery chargers are also provided to supply emergency power through an inverter circuit for a limited time. This will supply critical loads which may receive emergency power and include turbine lube oil equipment, lighting, instrumentation, and control equipment.

COST ENGINEERING METHODS

A. COST ENGINEERING OBJECTIVES

The cost engineering objectives for the balance of plant are defined as providing the following:

- Conceptual balance-of-plant construction cost estimates
- Balance-of-plant maintenance cost estimates
- Estimates of time required for construction

Balance-of-plant costs include: installation costs for major components; both purchase and installation costs for all balance-of-plant material; and indirect field costs, engineering, home office costs, fees, and a contingency allowance. Escalation and interest during construction are excluded from the balance-of-plant construction cost estimates.

B. CAPITAL COST ESTIMATE APPROACH

Basis of Estimates

The balance-of-plant construction cost estimates are based on the following inputs:

- Energy conversion system data (for example, cycle diagrams, working fluids, flow rates, temperatures, pressures, and power ratings).
- Specifications for major components (for example, descriptions, dimensions, weights, extent of field assembly required, and ancillary equipment requirements).
- Balance-of-plant data generated in the study (for example, plant subsystems descriptions, solids-handling data, effluents, and water requirements).
- Balance-of-plant equipment lists generated in the study (for example, specifications for major pumps, transformers, condenser, feedwater heaters, main pipe sizes, fans, and stack dimensions).
- Conceptual plant layout drawings generated in the study including a plot plan, equipment arrangement plan and elevation, and a single-line electrical diagram.

An information flow diagram is shown in Figure 41 which indicates the above inputs, subsequent cost engineering activities working from these inputs to develop plant estimates, and reference items which were employed.

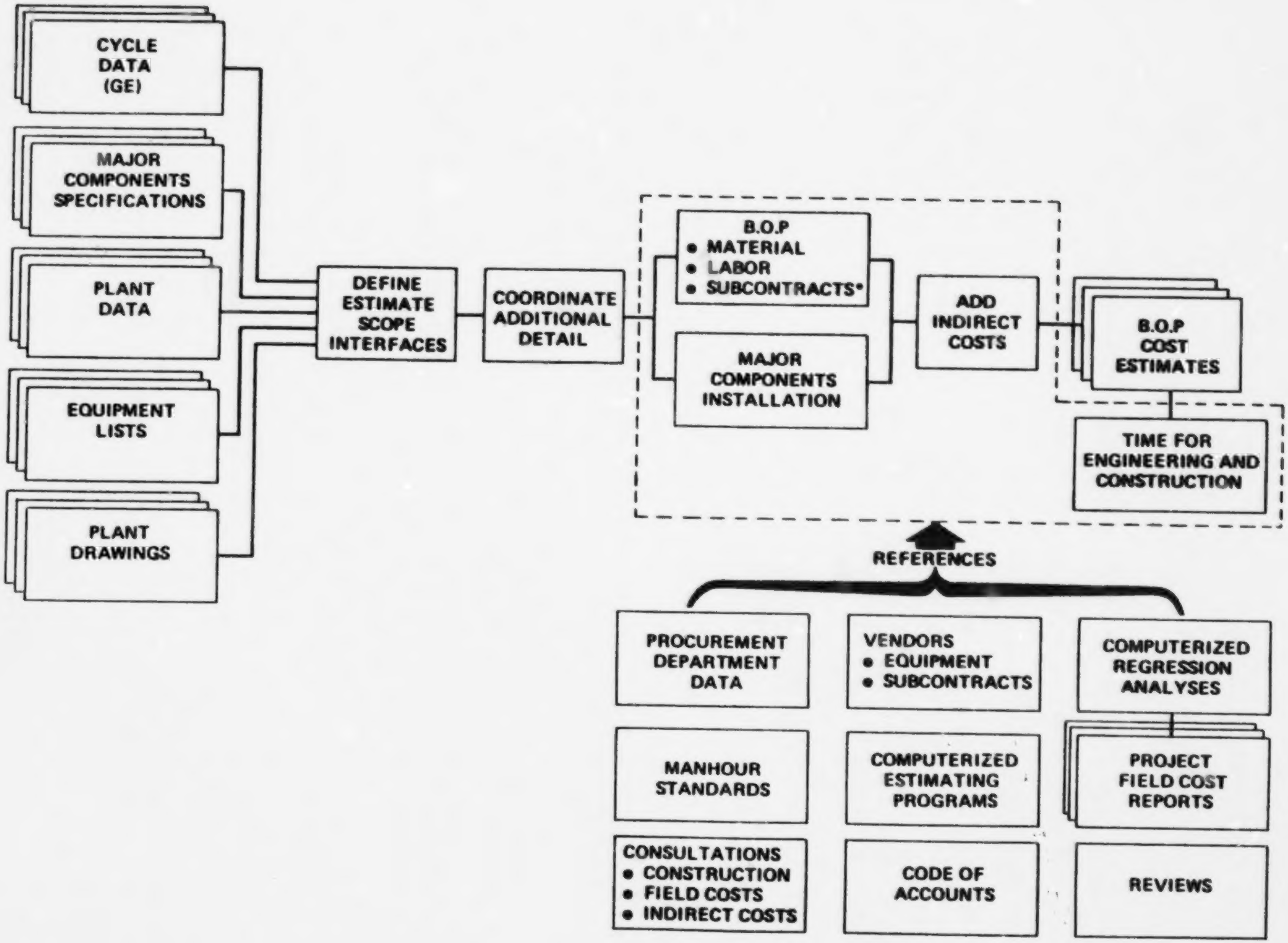
CYCLE DATA (GE)
MAJOR COMPONENTS SPECIFICATIONS
PLANT DATA
EQUIPMENT LISTS
PLANT DRAWINGS
DEFINE ESTIMATE SCOPE INTERFACES
COORDINATE ADDITIONAL DETAIL
B.O.P
• MATERIAL
• LABOR
• SUBCONTRACTS*
MAJOR COMPONENTS INSTALLATION
ADD INDIRECT COSTS
B.O.P COST ESTIMATES
TIME FOR ENGINEERING AND CONSTRUCTION
REFERENCES
PROCUREMENT DEPARTMENT DATA
VENDORS
• EQUIPMENT
• SUBCONTRACTS
COMPUTERIZED REGRESSION ANALYSES
MANHOUR STANDARDS
COMPUTERIZED ESTIMATING PROGRAMS
PROJECT FIELD COST REPORTS
CONSULTATIONS
• CONSTRUCTION
• FIELD COSTS
• INDIRECT COSTS
CODE OF ACCOUNTS
REVIEWS

Figure 41. Cost Engineering Task Flow Diagram

Direct Field Costs

Balance-of-plant (BOP) cost estimate summaries are presented according to the format shown in Table 96 and are accompanied by detailed itemized breakdowns of each direct field cost account. Seven direct field cost accounts are utilized. The use of these accounts facilitated the development and cross-checking of results with recent construction experience in fossil-fired power plants.

Two of the seven direct field cost accounts (1.0 Steam Generators/Furnaces and 2.0 Turbine Generators) include major components for which BOP estimates include only installation labor costs. One account (3.0 Mechanical Equipment) includes both major components in which BOP installation costs are supplied and BOP items that include component costs and installations. The remaining four accounts (4.0 Electrical, 5.0 Civil and Structural, 6.0 Piping and Instrumentation, and 7.0 Yardwork and Miscellaneous) include primarily BOP items--both component costs and installation costs. Details of these direct costs pertaining to particular energy conversion systems are presented in Section 4 of this report. Details of direct costs pertaining to BOP items that are common to all plants are discussed below under "Common Balance-of-Plant Components."

Table 97 gives an approximate division of items which are included in each account.

The BOP direct field costs are developed on the following basis:

1. All prices are at mid-1975 dollar value.
2. A composite labor rate of $11.75/MH is applied to all manual field labor.
3. Material and equipment costs are determined from current data, from vendors' oral budgetary quotations, and from recent power plant construction field cost reports.
4. Manual field labor man-hours are determined from man-hour standards, from computerized estimating programs, and from recent power plant construction field labor cost reports.
5. Productivity of manual field labor is assumed to be equivalent to the current national average for fossil-fired power plants.
6. Availability of manual field labor is assumed to be sufficient at the Middletown, U.S.A., site for construction of each plant.

Subcontracts

Subcontracts are not included as such in the cost estimates. BOP components that normally would be estimated as single subcontract cost entries (for example, cooling towers, stacks, and pipe insulation) are divided into, and entered as, direct material and direct labor costs.

Table 96

BALANCE-OF-PLANT COST SUMMARY FORMAT

	Labor (MHs)	Material ($)	Total ($)
1.0 Steam Generators/Furnaces	XX	XX	
2.0 Turbine Generators	XX	XX	
3.0 Mechanical Equipment	XX	XX	
4.0 Electrical	XX	XX	
5.0 Civil and Structural	XX	XX	
6.0 Piping and Instrumentation	XX	XX	
7.0 Yardwork and Miscellaneous	XX	XX	
Direct Materials		XX	XX
Direct Labor	XX @ $11.75/MH =		XX
Direct Field Cost			XX
Distributable Field Cost @ 90% of Direct Labor			XX
Total Field Cost			XX
Engineering, Home Office and Fee @ 15%			XX
			XX
Contingency @ 20%			XX
Balance-of-Plant Construction Costs			XX

Table 97

ACCOUNT CATEGORY DIVISIONS

1.0 STEAM GENERATORS/FURNACES

Steam Generators* and Economizers*

Coal Injection Systems*

Combustion Air Preheaters*

FD, PA, and ID Fans*

Flues and Ductwork

Precipitators,* Cyclones,* and Granular Bed Filters*

2.0 TURBINE-GENERATORS

Steam Turbine Generators*

Gas Turbine Generators*

3.0 MECHANICAL EQUIPMENT

Pumps and Drivers**

Condensers**

Heaters, Exchangers, Tanks, and Vessels**

Compressors and Drivers**

Stacks and Draft Ducts

Turbine Hall Cranes

Coal, Other Solids, and Ash Handling**

Cooling Towers

Water Treatment

Fuel Oil Ignition

Screenwell

Miscellaneous Plant Equipment

Equipment Insulation

Table 97 (continued)

4.0 ELECTRICAL

- Transformers
- Generator Main Bus
- Switchgear and Control Centers
- Communications and Lighting
- Grounding, Cathodic, and Freeze Protection
- Auxiliary Diesel Generator
- Conduit, Trays, Wire, and Cable

5.0 CIVIL AND STRUCTURAL

- Concrete Substructures and Foundations
- Superstructures and Building Services
- Earthwork, Dewatering, and Piling
- Cooling Tower Basin
- Circulating Water Pipe and Pump Pads

6.0 PIPING AND INSTRUMENTATION

- Steam and Feedwater Piping
- Hot Gas Piping
- Auxiliary Piping
- All Small Piping (2 in. and under)
- Hangers and Supports
- Miscellaneous Labor Operations
- Pipe Insulation
- Instrumentation and Controls

Table 97 (continued)

7.0 YARDWORK AND MISCELLANEOUS

- Site Preparation and Improvements
- Site Utilities
- Railroad Spurs
- Roads, Walks, and Parking Areas
- Yard Fire Protection
- Fences and Gates
- Ponds and Dikes
- Lab, Shop, and Office Equipment

*Install only
**Some installed only

This procedure is adopted to ensure a comprehensive accounting of all field labor man-hours. In effect, this method assumes that all field labor is performed by the prime contractor's work forces.

Distributable Field Costs

Distributable, that is, indirect, costs include field costs that cannot be directly identified with any specific direct account item. In a sense, the costs are "distributed" over all direct items. Construction experience demonstrates that distributable field costs can be estimated as a percentage of direct field labor costs. For each system, distributable costs are estimated at 90 percent of direct field labor cost--a percentage that is consistent with recent fossil-fired power plant construction experience. The items included in the distributable account and the typical percentages are given in Table 98.

Engineering, Home Office Costs, and Fees

Recent fossil-fired power plant construction experience demonstrates that engineering, home office costs, and fees are equal to approximately 15 percent of total (that is, direct plus indirect) field costs. Included in these costs are:

- Design engineering
- Estimating, scheduling, and cost control
- Purchasing, expediting, and inspection
- Construction management and administration
- Engineering, procurement, and construction management fees

Fees typically amount to about 2 percent of total field costs. About two-thirds of the remaining 13 percent are for engineering services and the remaining third is for other home office costs.

Contingency

Estimates predict the cost of a project but predictions contain uncertainties. Contingency is the amount of money that construction experience has demonstrated must be added to an estimate to provide for uncertainties within the design detail in quantity, pricing, and productivity.

Contingency minimizes the risk of these uncertainties and reflects a selected risk of overrun. The contingency is expected to be spent during the construction and is selected to yield the most probable total project cost. Contingency does not provide for changes in the defined scope of a project or for unforeseeable circumstances beyond the contractor's normal experience or control.

Table 98

DISTRIBUTABLE FIELD COSTS

• Temporary construction facilities including sheds, temporary fences and paving, temporary utility connections	12%
• Miscellaneous construction services including surveying, material handling, watchmen and clean up	12%
• Construction equipment and tools	10%
• Consumables including fuel, oxygen, acetylene and welding rod	5%
• Field office costs including field supervision, field engineering, field administration, medical and field office overhead expenses	20%
• Preliminary operations and testing including alignment, balancing, testing and adjusting of all equipment to ensure that warranties are met and that all subsystems function properly prior to customer acceptance and plant startup	11%
• Payroll expenses including federal and state payroll taxes and workmen's compensation	14%
• Project insurance	4%
• State and local sales and use taxes	2%
	90%

A contingency of 20 percent applied to all costs has been selected with consideration of the conceptual nature of the designs. The limited conceptual level of detail in these plant designs increases the risk of underestimating costs. To compensate, a contingency is selected that is near the high end of the range of values currently used in the construction industry.

A common contingency factor (20 percent) is applied to all three plant types studied. A common percentage is justified because, by definition, contingency reflects a level of uncertainty consistent with the design detail, and all plants are estimated at a common conceptual level of available detail. By definition, contingency does not reflect technological risks which may be associated with the more advanced systems.

Design Allowances

Design allowances are also built into estimates to cover costs that experience indicates are expected but not explicitly identifiable. However, unlike contingency, which is an indirect cost applied to a total estimate, design allowances are direct costs applied to specific equipment or bulk material items. For example a 5-percent design allowance may be added to the purchase price of a pump to cover expected miscellaneous field purchases required to facilitate installation of that pump. Design allowances typical to current fossil-fired power plant estimates are included in the estimates.

C. COMMON BALANCE-OF-PLANT COMPONENTS

Certain significant BOP components are common to all or many of the energy conversion systems.

Stacks and Accessories

In actual plant construction, stacks are usually subcontracted. Budgetary direct material costs and labor requirements were estimated through consultation with a stack contractor. An additional allowance for accessories, including lifts, marker lights, and paint is estimated from recent construction experience. Budgetary direct material costs for a stack with accessories (excluding stack foundation) are estimated from the relation:

$$\left(\frac{\text{Stack height (ft)}}{470}\right)^{1.05} \times \left(\frac{\text{Liner diameter (ft)}}{40}\right)^{0.55} \times \$1{,}000{,}000 + \$15{,}000$$

Corresponding direct labor man-hour requirements are:

$$\left(\frac{\text{Stack height (ft)}}{470}\right)^{1.35} \times \left(\frac{\text{Liner diameter (ft)}}{40}\right)^{0.75} \times 48{,}000\ \text{MH} + 1{,}100$$

Concrete for stack foundations is estimated using reinforcing bar, formwork, and embedded metal quantities per cubic yard as experienced in recent field construction.

Cooling Towers

Cooling towers are defined as wood, mechanical draft, wet towers operating at the design conditions detailed earlier in this Section.

Cooling towers are usually subcontracted, though, budgetary estimates on direct material costs and labor requirements were estimated through consultation with a cooling tower contractor. Cooling tower costs are estimated on the basis of tower units (TU) which, for the tower design specified are:

At mid-1975 dollar values, direct material costs for the towers are $6.13/TU.

The corresponding direct field labor requirements are 0.14 man/hours/TU.

Concrete for the cooling tower basin and foundations is estimated using 275 cubic yards (210 m^3) per cell and using reinforcing bar, formwork, and embedded metal quantities per cubic yard as experienced in recent field construction.

An allowance of $6,000/cell and 100 MH/cell is also estimated for miscellaneous structural steel and fire-protection equipment based on recent construction experience.

Dewatering and Piling

Dewatering and piling requirements are site sensitive and dependent on soil conditions, groundwater, rainfall, and so on. For all plants, an allowance of $300,000 for material costs and 100,000 man-hours is included for dewatering and piling based on recent field construction experience.

Auxiliary Buildings

Administration, warehouse, and minor yard buildings are, in large part, dependent upon the plant owner's particular needs. Based on typical costs for these buildings extracted from recent coal-fired power plant construction projects, the following allowances are included for auxiliary buildings in all plants:

	Direct Field Labor	Direct Field Material Cost
Earthwork	600 MH	--
Substructures	5,400 MH	$ 36,000
Building Services	84,000 MH	$ 1,250,000

Railroad Spur

All plants include four miles of railroad trackage for unit-train delivery of coal and sorbent material and for removal of solid waste. Based on recent construction experience, $632,000 for material costs and 21,500 man-hours are allocated for the railroad spurs.

Other Common Equipment

All plants include costs for the following equipment items:

- Laboratory and office equipment (@ $285,000 equipment cost and 1,000 man-hours allowed for handling and installation)
- Mobile coal-handling equipment including two bulldozers with coal blades and two scrapers (@ $908,000 for the lot)
- 1,000 kW, 480 V, 3-phase auxiliary diesel generator with startup batteries and associated equipment (@ $115,000 equipment cost and 1,500 man-hours for installation)

Several additional balance-of-plant components are common to all plants but vary in cost according to capacity or other scaling parameters. These components are listed in Table 99 along with the scaling parameter used in deriving their costs.

Plant equipment and material not discussed in this section are particular components required by specific energy conversion systems. These components (for example, boilers, combustors, turbine generators, feedwater heaters, pumps, fans, large piping, and boiler enclosures) are estimated on an item-by-item basis and discussed in the CWS, AFB, and PFB sections of the report.

D. CONSTRUCTION TIME ESTIMATES

For large fossil-fired power plants of the type included in this study, a relationship exists between the total number of field manual man-hours and the number of months required from start of plant engineering to construction completion. This relationship is presented in Figure 3-6, which is plotted using data from actual power plant construction experience. Data points represent coal- and oil-fired, single- and double-unit plants of 500 MWe and 800 MWe unit-capacity. The line drawn between points is the result of a least-squares regression analysis and indicates the following exponential relation:

$$\text{Construction Time* (Months)} = 47.5 \times \frac{\text{Manual Labor (MH)}}{10^6}^{0.20}$$

Using the above relationship, a construction time is estimated for each of the plants included in this study and presented in Table 3-6.

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*From start of engineering to commercial plant operation

Table 99

COMMON BALANCE-OF-PLANT COST ITEMS

Balance-of-Plant Item	Cost Scaling Parameter(s)
Turbine hall crane	Turbine rating (MWe)
Solids-handling equipment (includes railcar dumping, dust collectors, primary crushing, belt scale, sampling station, magnetic cleaners, conveyors, hoppers, feeders, foundations, pits, and tunnels)	Solids-flow (TPH) and conveyor lengths
Water treatment and chemical injection	Gross plant rating (MWe)
Instrument air compressors and auxiliaries	Gross plant rating (MWe)
Fuel oil ignition and warmup	Gross plant rating (MWe)
Screen well	Gross plant rating (MWe)
Miscellaneous mechanical equipment	Gross plant rating (MWe)
Equipment insultation	Gross plant rating (MWe)
Main transformer and generator main bus	Voltages (kV) and capacity (MVA)
Station service transformers	Voltages (kV) and capacity (MVA)
Startup transformer	Voltages (kV) and capacity (MVA)
Plant electrical equipment (includes switchgear and load centers, motor control centers, local control stations, distribution panels, relay and meter boards, communications, grounding, cathodic and freeze protection, preoperational testing)	Station service transformer cost
Plant lighting	Lighted plant area (ft^2)
Electrical bulk materials (includes conduit, cable trays, wire, and cable)	Station service transformer cost
Turbine halls (include substructure and building services)	Building plant area (ft^2)
Circulating water system (includes concrete and pipe)	Circulating water flow (gal/min)
Miscellaneous equipment foundations and other concrete	Gross plant rating (MWe)
Common large piping (includes auxiliary steam, condensate, process water, fuel and ignition oil, water treatment, compressed air, lube oil, H_2, CO_2, miscellaneous)	Gross plant rating (MVA)
Small piping, valves, and fittings 2 inches or less in diameter	Linear feet of large pipe (ft)
All pipe hangers and supports	Piping cost ($)
Miscellaneous piping labor operations (includes material handling, scaffolding, clean up)	Piping man-hours (MH)

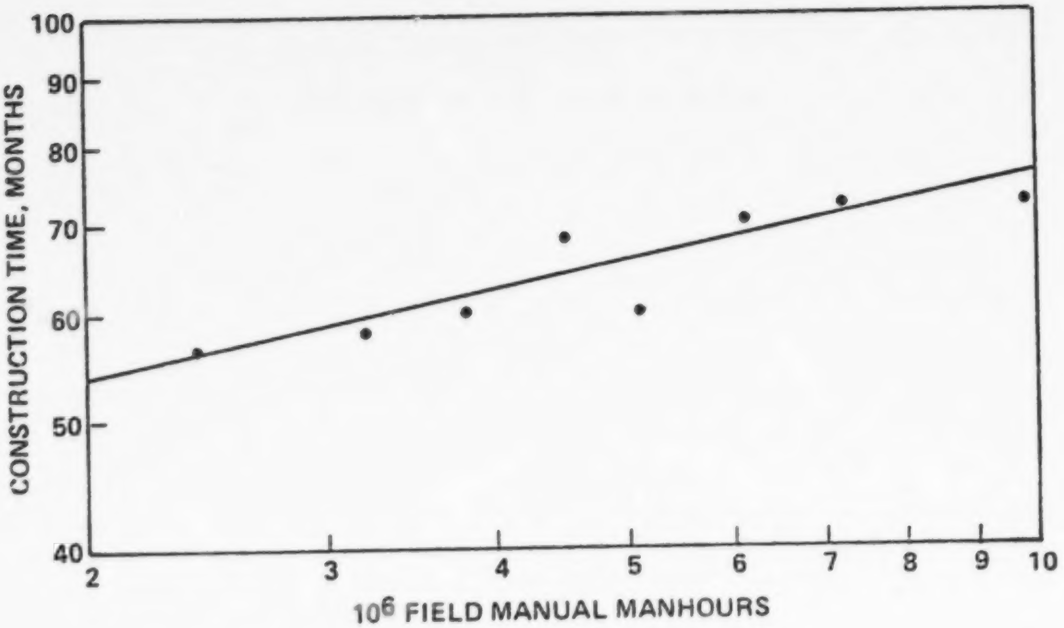

Figure 42. Construction Time (from Start of Engineering) to Commercial Operation) Variation with Field Manual Labor Man-Hours

Table 100

ESTIMATED PLANT CONSTRUCTION TIMES

	Manual Labor (MHs)	Construction Time (Months)
Conventional/Wet Scrubber	5,602,000	66
Atmospheric Fluidized Bed	4,295,000	64
Pressurized Fluidized Bed	3,995,000	64

F. OPERATING AND MAINTENANCE COSTS

1. INTRODUCTION

The analysis of operating and maintenance (O&M) costs was a joint effort of several organizations.

General Electric Installation and Service Engineering Business Division was responsible for bringing together estimates on the maintenance costs associated with conventional types of power plant equipment and for estimates of the operating labor costs associated with each system. This Division also played a major role in the study of operating consumable costs. Foster Wheeler Energy Corporation supplied maintenance data and information on the atmospheric and pressurized fluidized bed concepts. The Bechtel Corporation supplied listings of balance-of-plant equipment which have served as the basis for maintenance estimates on this equipment.

General Electric Corporate Research and Development performed the following activities:

Provided detailed information on the characteristics of the energy conversion concepts.

Investigated maintenance requirements associated with advanced components.

Carried out analyses of operating consumables costs for the advanced concepts.

Integrated the several efforts into a single analytic package.

O&M costs have been estimated for the CWS, AFB, and PFB power plants. For each of these plants, total operating and maintenance costs are computed in mills per kilowatt hour. Each total is the sum of estimated maintenance costs on cycle equipment, the operating labor required for the plant, and the cost of operating consumables.

All costs are based on mid-1975 cost estimates, without provision for inflation in costs over system life. Differential costs of "makeup" purchases of power are not included.

Costs of such items as auxiliary power purchases, outside steam purchases, other utilities, taxes, and insurance are not estimated in O&M costs. Items usually handled by applying a fixed charge rate to the total capital investment (for example, cost of working capital and capital charges) are not included in O&M costs.

2. MAINTENANCE COSTS

The maintenance costs include the costs during planned outages (preventive maintenance, inspections), and forced outages (breakdowns, repairs). The costs include any unusual supplies, replacement parts, equipment rentals, outside maintenance consultants, and the salaries of the employees required in providing the necessary maintenance. The salaries of these maintenance men are the major component of the maintenance costs of power plant equipment. No costs are estimated to provide a contingency for major repairs that might be required in the event of a long forced outage caused by severe parts failure damage. Plant maintenance is broken down into the following areas for cost estimation:

a. Turbine-generator

b. Steam generator

c. Makeup water treatment

d. Electrostatic precipitator

e. Water intake structure

f. Balance of plant (BOP)

This cost breakdown is shown in Table 101.

a. Turbine-Generator Units

The estimated maintenance cost for an entire steam turbine generating unit included supervision and engineering as well as maintenance of structures, boiler plant and electric plant.

The PFB plant required maintenance of a gas turbine generator as well as an addition to it also.

Gas turbine-generator maintenance costs include the maintenance of an industrial continuous service baseloaded gas turbine-generator only and excludes any associated equipment.

b. Steam Generators

The Foster Wheeler Energy Corporation has supplied estimates for the atmospheric (AFB) and pressurized (PFB) fluidized bed systems. Each system has been broken down in terms of four maintenance-sensitive areas: pressure parts, special fluidized bed items, control components, and auxiliary equipment. Separate maintenance burdens were then applied to each of the four, these burdens ranging from 0.2 percent to 5.0 percent annual maintenance costs as a percentage of equipment cost. These analyses have resulted in the estimation of annual maintenance costs of roughly $1,kW for the AFB to about $1.70/kW for the PFB.

Foster Wheeler also supplied estimates for the conventional pulverized coal-fired furnace for the Conventional/Wet Scrubber plant design.

c. Makeup Water Treatment System

Makeup water treatment costs were based on makeup water flow. The system was assumed to be two stage: (1) pretreatment solids removal incorporating flocculation and filtration using carbon and sand and (2) a demineralization stage composed of a dual-bed demineralizer, atmospheric degasifier, and a dual mixed-bed demineralizer as major components.

The maintenance cost for water treatment does not include chemicals costs, which are treated as consumables.

d. Electrostatic Precipitator

The CWS and AFB plants utilized electrostatic precipitators. The ESP efficiencies for the plants were 95 percent for the AFB and 98.5 for the CWS. On the basis of these efficiencies maintenance costs were calculated based on gas flow.

e. Water Intake Structures

Water intake structures were assumed to be a bar screen and traveling screen system. Maintenance costs were based on equipment replacement costs with magnitudes proportionally determined by makeup water flows.

f. Balance-of-Plant Maintenance Costs

Maintenance costs, as well as being estimates for conventional and advanced cycle equipment, have been separately calculated for balance-of-plant, (BOP) equipment.

The rationale for these calculations may be briefly described as follows: Bechtel Corporation has supplied detailed estimates of BOP material costs associated with major equipment categories for each cycle: that is, steam generators, turbine generators, process mechanical equipment, electrical, civil and structural, process piping and instrumentation, and yard work and miscellaneous. Within each category, maintenance costs as a fraction of the material costs per year have been estimated. For example, the maintenance burden on miscellaneous support steel is taken to be 0.2 percent per annum, whereas those for forced draft fans, pumps, etc., are taken at 5 percent per year. Other categories of equipment have been similarly assigned maintenance burdens in accordance with good engineering judgment and field experience.

These maintenance burden factors are then multiplied by the associated BOP materials costs for each equipment class, with all such products then summed to create a maintenance cost for the entire cycle in \$M/yr. These cost figures are in turn (based upon the cycle's net output in MW and a 65% capacity factor) converted to BOP maintenance costs in mills/kWh for each cycle.

3. OPERATING COST ESTIMATES

The operating cost estimates for the three plants studied are broken down into operational labor costs and into costs of consumables and supplies.

a. Operational Labor Costs

Estimates of the manpower required to operate the three power plants were based upon available information contained in the references and upon extrapolations of such estimates to cover the advanced technology aspects of the various plants. Basic categories of labor considered as operating personnel include supervisors, engineers, operators, technicians, fuel handling specialists, chemical technicians, clerical workers, laborers, guards, and others. These categories were consolidated into:

a. Supervisors
b. Operators
c. Technicians
d. Laborers, clerks, guards, others

Once the number of employees for each power plant was established, the annual payroll including fringe benefits and overhead was calculated assuming an average salary of $20,000/year:

Composed of:	14,286	base salary
	4,285	fringe benefits
	1,429	overhead
	$20,000	Total

The estimated manpower requirements and associated costs are found in Table 102.

b. Consumables and Supplies

The major portion of consumable costs is that required for the purchase of sulfur dioxide sorbents. The AFB and CWS plants both require limestone while the PFB utilizes dolomite. A charge of $5.00/ton is assumed for both limestone and dolomite. An average cost for water, lubricants, and supplies was calculated from existing coal-fired plant data resulting in an average 1975 cost of 0.20 mill/kWh. It was then assumed that these consumables apply to that portion of the plants which is considered conventional equipment. The cost for consumable is assumed to cover the cost of water where it must be purchased for makeup, and for the necessary water treatment chemicals; water treatment was estimated to cost $2.11/1000 gal of water treated.

c. Solids Disposal

No disposal costs are included in the GE estimates for AFB and PFB. CWS solids disposal costs are included in the form of disposal pond and sludge handling costs.

Table 101

MAINTENANCE COSTS

CWS (747 MW)	$M/Yr.
Steam Turbine-Generator	1.10
Conventional Furnace	1.44
Makeup Water Treatment	0.04
Electrostatic Precipitators	0.32
Water Intake Structure	0.04
BOP	1.96
Wet Scrubber System	1.69
Total	6.59

AFB (814 MW)	
Steam Turbine Generator	1.20
AFB Units	0.88
Makeup Water Treatment	0.04
ESP	0.11
Water Intake Structure	0.04
BOP	1.85
Total	4.12

PFB (904 MW)	
Steam Turbine Generator	0.98
Gas Turbine Generator	0.72
PFB Units	1.48
Makeup Water Treatment	0.03
Water Intake Structure	0.03
BOP	1.89
Total	5.33

Table 102

OPERATING LABOR

Plant	Supervision	Operators	Fuel Syst Tech Chem Tech	Laborers, Clerks, Guards, etc.	Total Operating Personnel	M$/Yr	Net Output	Mills/kWh
AFB	17	50	18	25	110	2.20	814	0.47
CWS	14	42	15	20	91	1.82	747	.43
PFB	17	50	18	25	110	2.20	904	0.43

Table 103 contains costs associated with consumables and supplies for each of the three power plants.

4. O&M SUMMARY

The number of personnel required to operate and maintain a power plant will be partly dependent on the staffing practices of the particular utility operating the plant. Some utilities account for those employees not directly applicable to power plant O&M, while others hire some of their services from outside subcontractors.

If the utility operating a plant had several other large plants nearby so that certain of the maintenance personnel, engineers, and technicians could be shared, their staffing would be accounted in a different way. Our manpower estimates represent judgment as to the average number of employees for each of the plant types. Other factors influencing staff sizes are site-related or region-related or effects, such as specific union negotiated manpower requirements by job classifications and labor productivity.

The values selected for maintenance costs on the major equipment items also depend on the specific practices for routine preventative maintenance and on the forced outage experience on each equipment item. Maintenance costs will depend on achieved equipment reliability. An additional complication causing a range of values for maintenance costs in various survey reports is that of accounting practices, by which one may keep track of maintenance expenses on each individual item of equipment while others may group the expenses by systems or other categories. The estimated values for maintenance costs are to be taken as representative of a wide range of data reported by the various utilities.

Table 104 gives a detailed breakdown of all O&M costs. These costs are summarized in Table 105.

Table 103

OPERATING CONSUMABLES

CWS

Conventional: 0.91×10^6 \$/yr.

Limestone: $125{,}000^{a} \times \frac{\$5^{b}}{2000} \times 8760 \times .65 = 1.78 \times 10^6$ \$/yr.

Total: $0.91 + 1.78 = 2.69 \times 10^6$ \$/yr.

$$\frac{\$2.69 \times 10^6 \times 1000 \text{ mills/dol}}{747 \text{ MW} \times 1000 \text{ kW/MW} \times 8760 \times .65} = \underline{.63 \text{ mills/kWh}}$$

AFB

Conventional: 1.05×10^6 \$/yr

Limestone: $(48{,}564.8 \times 4 \times 1.0626 \text{ lb/hr})^{a} \times \frac{\$5}{2000} \times 8760 \times .65$

$= 2.94 \times 10^6$ \$/yr

Total: $2.94 + 1.05 = 3.99 \times 10^6$ \$/yr

$$\frac{\$3.99 \times 10^6 \times 1000 \text{ mills/dol}}{814 \text{ MW} \times 1000 \text{ kW/MW} \times 8760 \times .65} = \underline{.86 \text{ mills/kWh}}$$

PFB

Conventional: $.82 \times 10^6$ \$/yr

Dolomite: $(83{,}963 \times 4)^{a} \times \frac{\$5^{b}}{2000} \times 8760 \times .65 = 4.78 \times 10^6$ \$/yr

Total: $.82 + 4.78 = \$5.60 \times 10^6$ \$/yr

$$\frac{\$5.60 \times 10^6 \times 1000}{904 \text{ MW} \times 1000 \times 8760 \times .65} = \underline{1.09 \text{ mills/kWh}}$$

a. Hourly throughout, total plant
b. Cost of dolomite or limestone per pound

Table 104

DETAILED O&M COSTS

1. CWS (747 MW)

Maintenance Costs		(Mills/kWh)
Steam turbine generator		0.26
Conventional boiler		0.33
Makeup water treatment		0.01
Electrostatic precipitators		0.08
Water intake structure		0.01
Scrubber system		0.40
Balance of plant (BOP)		0.46
	Total	1.55
Operational Costs		
Labor (91 Men)		0.43
Consumables		0.63
	Total	1.06
Total O&M Costs		2.61

2. AFB (814 MW)

Maintenance Costs		(Mills/kWh)
Steam turbine generator		0.26
AFB		0.19
Makeup water treatment		0.01
Electrostatic precipitators		0.02
Water intake structure		0.01
BOP		0.40
	Total	0.89
Operational Costs		
Labor (110 Men)		0.47
Consumables		0.86
	Total	1.33
Total O&M Costs		2.22

Table 104 (continued)

3. PFB (904 MW)

Maintenance Costs		(Mills/kWh)
Steam turbine generator		0.19
Gas turbine generator		0.14
PFB		0.29
Makeup water treatment		0.01
Water intake structure		0.01
BOP		0.37
	Total	1.01
Operational Costs		
Labor (110 Men)		0.43
Consumables		1.09
	Total	1.52
Total O&M Costs		2.53

Table 105

OPERATING AND MAINTENANCE COSTS
SUMMARY TABLE

Plant	Maintenance	Operation	Total O&M
CWS	1.55	1.06	2.61
AFB	0.89	1.33	2.22
PFB	1.01	1.52	2.53

G. GE COMPARISON OF ALTERNATIVES

Future steam power plants may use atmospheric fluidized beds (AFB) for burning coal in the presence of limestone, to provide sulfur capture during combustion. A more advanced concept would be the use of pressurized fluidized beds (PFB) with dolomite for sulfur capture and gas turbines for pressurizing. Such plants have been evaluated in the Energy Conversion Alternatives Study (ECAS)[5] on the identical basis and to the same degree of detail as the steam plants of this evaluation.

Table 106 compares these alternatives to the conventional steam plants with 175 F stack temperature (CWS 175). The basis for all table entries is $/kW of net plant output. The combination of Furnace Modules, Hot Gas Filtering, Solids Handling, and Stack Gas Scrubbers expresses much of the cost of heat release and sulfur and particulate capture. These accounts aggregate $67/kW for the AFB, $123/kW for the PFB, and $147/kW for the CWS. The total capital cost and the cost of electricity (COE) follow a similar progression.

The consumption of coal relates directly to the overall efficiency of a power plant. A number of alternatives were evaluated and are presented in Table 107 in the order of decreasing efficiency. The two "no scrubber" cases would require a coal with less than 0.65 percent sulfur for a 10,788 Btu/lb (25.1 MJ/kg) higher heating value if they were to meet the emission standards common to all of these plants. The boiler efficiency follows the same progression as the overall efficiency. The steam turbine cycle efficiency equal to 3412 divided by the heat rate also decreases toward the bottom of the table. The conventional furnace with wet scrubber and 175 F is the best current solution for combustion of high-sulfur fuels. The penalty in efficiency and cost of electricity are direct results of the environmental constraints, which are fully met.

The comparative amounts of sorbent required for sulfure capture are presented in Figure 43. Both the conventional steam plant with wet scrubbers and the AFB plant use limestone. The excess applied is 10 percent for the former and 100 percent for the latter. The PFB plant uses dolomite, which has only half the concentration of available lime found in limestone. The conventional plant consumes the least sorbent material. The solid wastes combine the ash and the solid products from sorbent reactions.

The major water usage is evaporation from the cooling towers. The major water waste that must be treated would be the cooling tower blowdown. Figure 44 shows the same progression in water conservation that would be found in coal requirement.

Table 106

CAPITAL COST DISTRIBUTIONS AS $/kW
FOR 3500 PSI, 1000 F, 1000 F STEAM POWER PLANTS

	AFB 1550 F	PFB 1650 F	CWS 175 F	CWS 250 F
Major Components				
Steam Turbine-Generator	33.2	27.7	33.6	34.8
Furnace Modules	55.8	16.3	57.7	61.4
Gas Turbines		28.3		
Hot Gas Filtering		71.4*		
Economizer		2.5		
Solids Handling	11.4	35.6	15.0	15.9
Subtotal	100.3	182.0	106.2	112.2
Balance of Plant				
Stack Gas Scrubbers	-	-	56.8	69.5
Site Labor	117.8	108.4	126.8	134.9
All Other	122.1	98.7	107.5	133.3
Subtotal	239.9	207.1	307.5	337.7
Contingency	68.0	77.8	82.9	90.0
Escalation and Interest	223.8	255.8	273.0	295.8
Total Capital Cost	632.	723	770	835
COE Mills/kWh	31.7	34.1	37.0	39.8

*Estimate of hot gas filtering costs for PFB, prepared by Westinghouse for ECAS was approximately $15/kW.

Table 107

EFFICIENCY ORDER OF STEAM PLANTS

Type Plant	Conditions	Stack	Overall Efficiency	Electricity Mills/kWh
PFB	1750 F Beds	300F	40.0%	34.1
PFB	1650 F Beds	300F	39.2%	34.1
CF	No Scrubber	250F	36.2%	30.5*
AFB	1550 F Beds	250F	35.8%	31.7
CF	No Scrubber	300F	35.7%	31.6*
CWS	Wet Scrubber	175F	33.8%	37.0
CWS	Wet Scrubber	250F	31.8%	39.8

*3.9% in coal not permitted

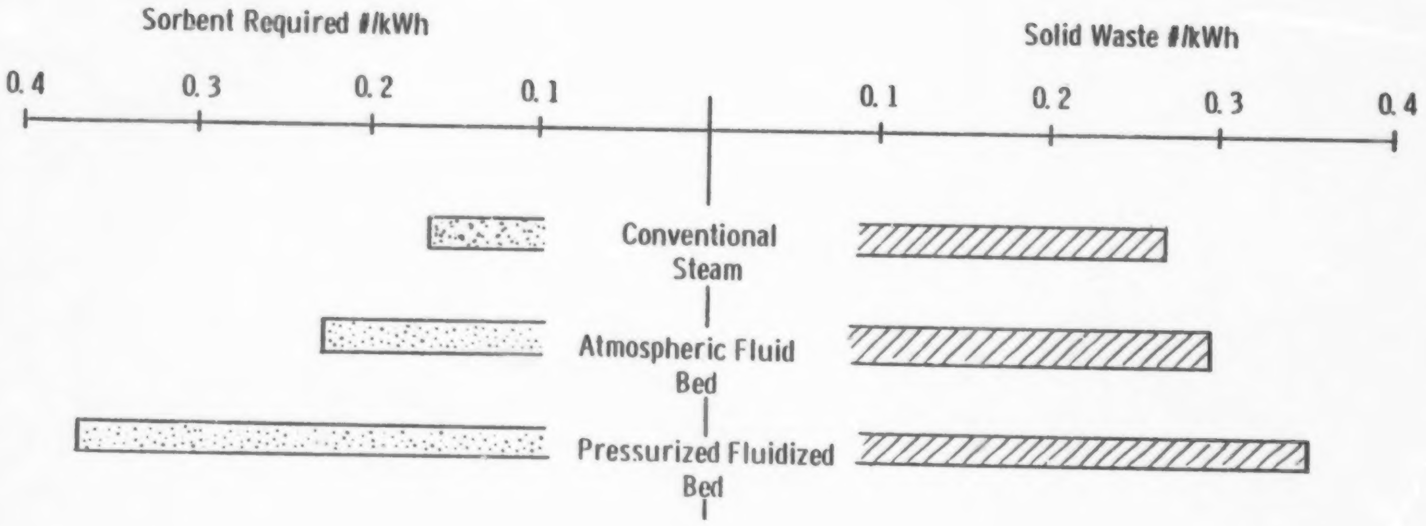

Figure 43. Solids Requirement

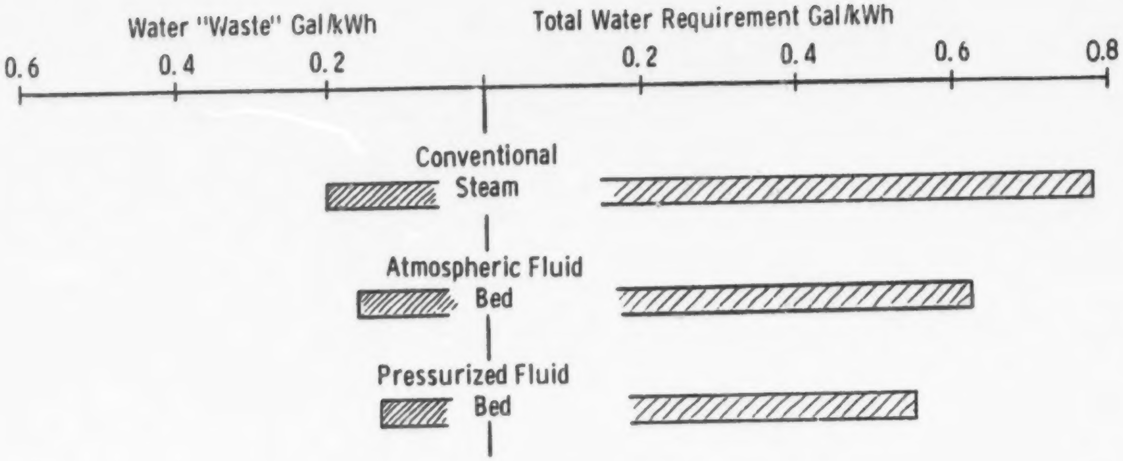

Figure 44. Water Requirement

The gaseous emissions of SO_x and NO_x are compared in Figure 45. The AFB and PFB, with combustion in beds at 1550 F and 1650 F respectively, have produced notably low levels of NO_x. The conventional furnace requires a well balanced, staged combustion system in order to meet current NO_x limitations. All plants satisfy the SO_x limits, with the PFB showing the greatest margin.

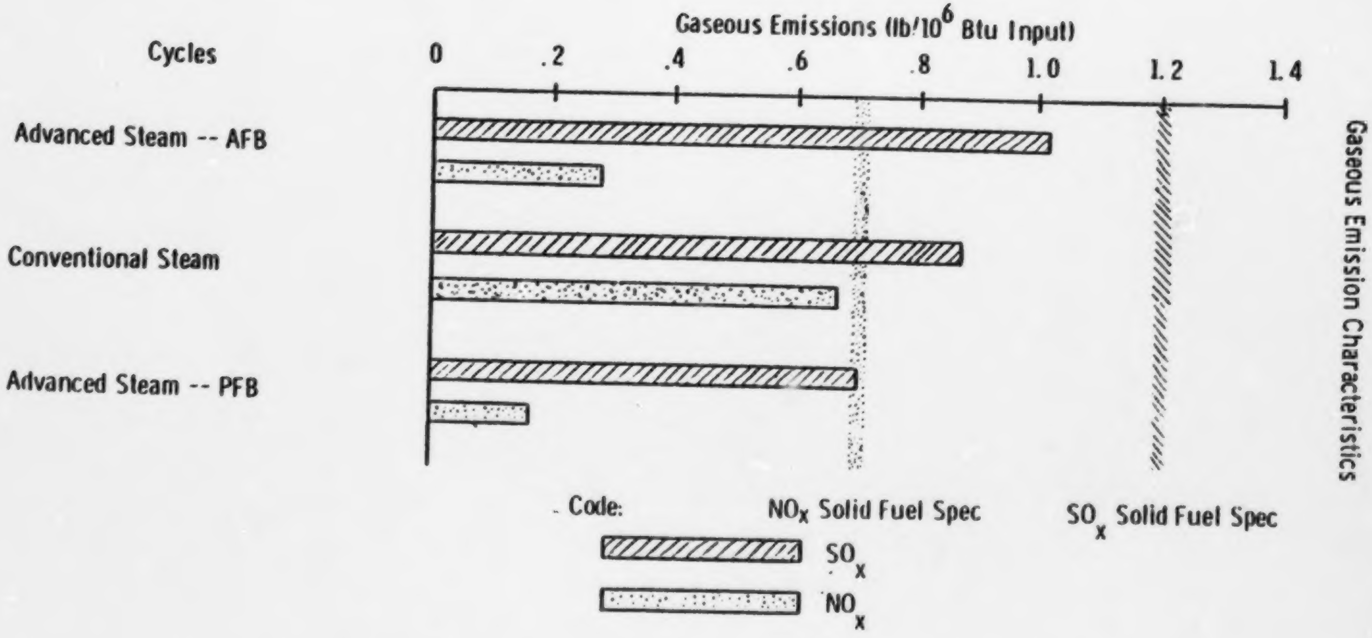

Figure 45. Gaseous Emission Characteristics (Lb/10^6Btu Input)

TVA MODIFICATION AND EXPANSION OF GE STUDY

A. INTRODUCTION

The capital and operating costs prepared by GE for the CWS, AFB, and PFB were modified by TVA to take into consideration a number of factors felt by TVA to be significant. Three major factors were addressed:

1. Modification of the estimates to include an uncertainty allowance allowance for plant components considered to be undemonstrated technology; and modification of the GE estimates for various components where such revision is felt to be warranted based upon TVA experience.

2. Expansion of the GE estimates to take into consideration alternate wet scrubbing techniques for the CWS case, in addition to the lime scrubber with on-site calcination used by GE.

3. Modification and expansion of the GE estimates of residue disposal costs, to take into consideration: (a) adequate provision for disposal over the full 30 year plant lifetime for all cases and (b) alternate disposal options. Previously, GE included only 5-year disposal provisions for the CWS case, and none for AFB and PFB.

B. MODIFICATION OF GE ESTIMATES BY TVA

Shown in Table 108 are the GE study cost comparison and TVA's modified cost estimates of the three types of steam plants. Both the GE and the TVA figures in Table 108 are based on the assumption that all three type plants are of a mature technology; they attempt to compare the costs of the three types of plants after they have been developed to a point of commercially acceptable risk for construction and operation. The TVA estimates include uncertainty allowances reflecting the fact that some of the plant components are not truly "mature technology" today. These allowances include items such as design changes, addition of equipment, and technological changes, and are an attempt to reflect what the costs for as yet undemonstrated components may actually turn out to be. These cost modifications do not incorporate development costs or startup costs associated with obtaining a state-of-art process.

TVA estimates in Table 108 also include increases in equipment costs and associated labor and material costs because the GE costs differed greatly from cost estimates based on quotations received by TVA. TVA cost figures for equipment were obtained from data presently on file. Cost of the components presently in an 800-MW and a 1200-MW coal-fired unit on the TVA system was escalated to mid 1975 dollars. Information from a recent cost estimate for three 867-MW coal-fired units was also used. These values were used to modify the GE study estimates.

These estimates should not be construed as an estimate of costs for which TVA believes these plants could be constructed today. TVA cost figures are only modifications of the GE study cost figures.

Uncertainty Allowance

TVA has assigned an uncertainty factor (unc.) to those items in the two fluidized bed concepts which are considered mature technology but on which full-scale development has not taken place. Those items are steam generators, fuel injection systems, spent solids and dust coolers, and portions of hot gas cleanup systems. This factor was applied for uncertainties of design and scale-up of components and not for costs to develop the components or to start up the process.

The amount of contingency added by EN DES was based on the following conditions:

Uncertainty	
20%	Development is currently at a point to provide reasonable confidence of commercial success.
40%	Development is currently at a point of reasonable definition of detailed technical problems to be solved.

Table 108

COST COMPARISON OF GE STUDY VS. TVA REVIEW

Total Capital Costs (1975 dollars)

PLANT TYPE	PLANT OUTPUT MW	GE STUDY TOTAL COST ($000,000)	GE STUDY COST/KW ($)	TVA REVIEW** TOTAL COST ($000,000)	TVA REVIEW** COST/KW ($)
*CWS @ 175 F	795.5	395.96	497.75	398.03	500.35
AFB	814.3	332.45	408.26	363.14	445.95
PFB	903.8	421.00	465.81	479.45	530.48
Total Capital Cost Escalated (5.5 year construction to mid-1981)					
CWS @ 175 F	795.5	613.74	771.5	616.95	775.6
AFB	814.3	514.70	632.0	562.87	691.2
PFB	903.8	653.10	722.8	743.15	822.3

*Scrubber is lime slurry w/8.5 ft/s gas velocity through scrubber, onsite calcination.

**Estimates by TVA include an uncertainty allowance for not-yet demonstrated components, and revisions of GE estimates for some components based upon TVA experience.

60%	Major technical breakthrough required to demonstrate acceptability of a system for commercial operation.

These uncertainty factors are in addition to the 20 percent contingency added to the total plant costs of each plant evaluated by General Electric. These factors were considered in the evaluation of the GE study cost estimates and the estimates were adjusted accordingly. The resulting estimates for the items of equipment that pertain to the above categories are as follows:

Atmospheric fluidized bed
(Process mechanical equipment)

	Equipment	BOP
1. Spent bed coolers Solids Cooler & Cyclones (add 20 percent unc.)		
Equipment cost: $312,000 x 2 x 1.2		.749M
Other equipment of spent bed cooling =		.276
		1.025M
2. Coal and limestone blending & feeding (add 20 percent unc.)		
All equipment $2.74M x 1.2	= 3.288	
BOP materials .930 x 1.2	=	1.116
Other process mechanical equipment Cost	= 5.81	
Other BOP material costs	=	28.394
Subtotal	$10.12M	$29.51M
(Component)		
3. Hot gas cleanup air supply Most items state of art except fines injection (add 20 percent unc.)		
Equipment cost $260,000 x 2 x 1.20	= .624M	
Other hot gas cleanup equipment	= 15.31	
Total equipment	= 15.93M	
BOP materials		0.61M
4. AFB module (add 20 percent unc.)		
Tower components, controls, ducts 29.72 x 1.2	= 35.66	
BOP materials 5.69 x 1.2	=	6.83
Subtotal	$51.59M	$7.44M

These are capital cost adjustments only. TVA cost estimates also adjusted labor as needed for both AFB and PFB.

	Equipment	BOP
Pressurized fluidized bed		
Process Mechanical Equipment		
1. Coal processing and feeding		
2 Petrocarb coal injection system (add 20 percent unc.)		
Equipment cost 7,198,354 x 2 x 1.20	= 17.28	
Remaining equipment	= 3.64	
Total coal process	20.92M	
2. Dolomite processing and feeding		
2 petrocarb injection system (add 20 percent unc.)		
Equipment cost 3,851,375 x 2 x 1.20	= 9.24	
Remaining equipment	= 2.03	
Total dolomite process	11.27M	
3. Spent bed material (add 40 percent unc.) to equipment, 20 percent to labor and materials)		
Equipment 1.58 x 1.40	= 2.21M	
BOP materials 3.57 x 1.2		4.28
Other process mechanical equipment component costs	= 5.39	
Other process mechanical equipment BOP material costs	=	22.63
Subtotal	$39.79M	$26.91M
Components		
4. Hot gas cleanup (add 20 percent unc.)		
Equipment 64.51 x 1.20	= 77.41	
BOP material 2.04 x 1.20	=	2.45

	Equipment	BOP
5. PFB module cost (add 40 percent unc.)		
Equipment 14.68 x 1.40	= 20.55	
BOP material 1.06 x 1.40	=	1.48
Subtotal	$97.96M	$3.93M

In addition to the uncertainty factors, modification of the following areas was involved in arriving at the TVA estimates.

Boiler Enclosure for PFB

To be consistent with the other to plants and TVA's practice to enclose its boilers, the following boiler enclosure costs were added to the pressurized fluidized bed costs.

Direct manual field labor - 41,000 MH
Material costs - $1.63M

Electrical Subsystems

TVA feels that the GE study estimate did not provide enough manpower and money for electrical subsystems. The largest difference in electrical costs between the GE study and TVA cost estimate is the cost of materials and labor for instrumentation and controls with TVA costs being much greater than allocated by the GE study estimate. The estimate for the remaining electrical equipment by TVA was actually less than the GE study. Although TVA uses an elaborate instrumentation and control system for its plants, this would only account for a small amount of the cost difference between EN DES and the GE study estimate.

Tables 109, 110, and 111 show the capital cost breakdown as modified by TVA for the CWS, AFB, and PFB plants.

The GE study estimate was reviewed for technical accuracy and suggested modifications were made for good utility design. The GE designs were considered technically accurate for equipment sizing, auxiliary losses, conditions of operation, and overall efficiencies.

The uncertainty factor had a major impact on the AFB and PFB cost estimates with very little impact on the conventional plant (CWS). In a cost comparison of CWS prime cycle and electrical equipment, the GE cost figures and TVA's recent cost figures for the 867-MW units were approximately the same.

There is no information available on utility wide accounting methods; therefore, no efforts to recommend changes in defining indirect cost is included. Therefore, the GE cost estimate for the conventional plant with scrubber is assumed to be reasonable and certainly attainable.

Table 109

TVA - CAPITAL COST BREAKDOWN
CONVENTIONAL STEAM PLANT - WET GAS SCRUBBERS - 175 F STACK (CWS 175)

COSTS (MILLIONS OF DOLLARS)

	CATEGORIES	COMPONENTS	DIRECT LABOR(1)	INDIRECT FIELD(2)	MATERIALS(3)	TOTAL
1.0	Steam Generators	45.88	13.40	12.06	8.70	80.04
2.0	Turbine Generator	26.75	1.41	1.27	0.10	29.53
3.0	Process Mechanical Equipment		7.76	6.98	43.30	58.04
4.0	Electrical[a]		8.99	8.09	11.77	28.85
5.0	Civil and Structural		12.10	10.89	16.10	39.09
6.0	Process Piping and Instrumentation[a]		16.40	14.76	23.68	54.84
7.0	Yardwork and Miscellaneous	———	3.06	2.75	1.70	7.51
		72.63	63.12	56.80	105.35	297.90
			BOP LABOR, MATERIALS & INDIRECTS (SUM OF 1 + 2 + 3)		225.27	
			A/E HOME OFFICE & FEE @ 15%			33.79
			TOTAL PLANT COST			331.69
			CONTINGENCY @ 20%			66.34
			TOTAL CAPITAL COST (BOP)			398.03
			ESCALATION & INTEREST			218.92
			TOTAL COST			616.95

(a) Revised by TVA to reflect reasonableness

TABLE 110 - AFB

TVA - EN DES - CAPITAL COST BREAKDOWN
ADVANCED STEAM CYCLE - ATMOSPHERIC FLUIDIZED BED

			COSTS (MILLIONS OF DOLLARS)		
CATEGORIES	COMPONENTS	DIRECT LABOR(1)	INDIRECT FIELD(2)	MATERIALS(3)	TOTAL
1.0 Steam Generators[b]	51.74	11.97	10.78	7.44	81.93
2.0 Turbine Generator	27.00	1.53	1.37	0.10	30.00
3.0 Process Mechanical Equipment[b]	10.12	6.27	5.64	29.51	51.54
4.0 Electrical[c]		10.90	9.80	12.83	33.53
5.0 Civil and Structural		10.40	9.36	13.70	33.46
6.0 Process Piping and Instrumentation[c]		11.63	10.47	17.46	39.56
7.0 Yardwork and Miscellaneous		1.59	1.43	1.70	4.72
	88.86	54.29	48.35	82.74	274.74
		BOP LABOR, MATERIALS & INDIRECTS (SUM OF 1 + 2 + 3)		185.88	
		A/E HOME OFFICE & FEE @ 15%			27.88
		TOTAL PLANT COST			302.62
		CONTINGENCY @ 20%			60.52
		TOTAL CAPITAL COST (BOP)			363.14
		ESCALATION & INTEREST			199.73
		TOTAL COST			562.87

(b) Contingency added by TVA.
(c) Revised for reasonableness by TVA.

Table 111 - PFB

TVA - EN DES - CAPITAL COST BREAKDOWN
ADVANCED STEAM CYCLE - PRESSURIZED FLUIDIZED BED
1650 F

COSTS (MILLIONS OF DOLLARS)

CATEGORIES	COMPONENTS	DIRECT LABOR(1)	INDIRECT FIELD(2)	MATERIALS(3)	TOTAL
1.0 PFB Steam Generators(b)	97.96	5.86	5.27	3.93	113.02
2.0 Turbine Generators	50.62	1.70	1.53	0.20	54.05
3.0 Process Mechanical Equipment(b)	39.79	6.51	5.86	26.91	79.07
4.0 Electrical(c)		10.14	9.12	11.66	30.92
5.0 Civil and Structural(d)		10.48	9.42	12.83	32.73
6.0 Process Piping and Instrumentation(c)		16.10	14.49	26.90	57.49
7.0 Yardwork and Miscellaneous		1.59	1.43	1.70	4.72
	188.37	52.38	47.12	84.13	372.00
		BOP LABOR, MATERIALS & INDIRECTS (SUM OF 1 + 2 + 3)		183.63	
		A/E HOME OFFICE & FEE @ 15%			27.54
		TOTAL PLANT COST			399.54
		CONTINGENCY @ 20%			79.91
		TOTAL CAPITAL COST (BOP)			479.45
		ESCALATION & INTEREST			263.70
		TOTAL COST			743.15

(b) Contingency added by EN DES.
(c) Revised for reasonableness by EN DES.
(d) Boiler enclosure addition.

In the TVA review of the plant plans provided with the study, it was apparent that all plants were compacted into a small area. Some areas would be inaccessible for maintenance of heavy equipment if required. It should be a utility's obligation to determine its own site layouts in accordance with their own design, land use, and equipment requirements.

Although modification to some equipment and to the site layout may be desirable, these changes were not added to the cost comparisons since they had negligible effect on costs.

TVA selected the GE 175°F stack gas temperature design as the CWS "base case." Considering lime scrubbers for 100 MW and larger units in the United States, none of the nine in operation reheat to over 175°F. Information available to TVA indicates that there are no benefits derived from reheating above 175°F. As added assurance of corrosion prevention at 175°F, budget cost figures for fiberglass ductwork and chimney liner are presented for information although not included in the TVA estimate for CWS.

Scrubbers with 175°F stack gas temperature could cause corrosion of the duct after the reheater and the steel chimney liners if the mist eliminators do not operate with maximum efficiency. To combat corrosion, the use of fiberglass ductwork and chimney liners capable of continuous 325°F stack temperature is proposed. The cost of fiberglass chimney liners 30 feet in diameter, 500 feet high is $1,100,000 for materials and installation. The cost of fiberglass ductwork from the mist eliminators to the stack is estimated at $1,700,000 for materials and installation. These cost figures should be substituted in the GE study for the respective chimney liner and ductwork, but, as stated above, these figures have not been included in the TVA estimates presented in this report.

C. ALTERNATIVE WET SCRUBBER CASES

The scrubber costs of the GE study were deemed reasonable for the six train lime scrubber using TVA Widows Creek unit No. 8 retrofit as a reference. However, cost estimates of a new plant indicate lower scrubber cost may be achieved when included in a total project cost. Costs could be reduced if the unit had four scrubber trains instead of six as provided by the GE study. Technology developments which permit an increase in scrubber thru-gas velocity from 8 ft/s to 12.5 ft/s make this possible.

Summarized in Table 112 are estimates of direct capital investment and direct operating costs in mid-1975 dollars for the following scrubbing systems:

- Lime scrubbing with onsite calcination
- Lime scrubbing without onsite calcination
- Limestone scrubbing
- Magnesium oxide regenerable scrubbing (production of sulfuric acid)

The scrubbers are preceded by a 99 percent efficient electrostatic precipitator. Onsite untreated ponding of scrubber wastes for a 30-year period is included in the lime and limestone scrubbing systems.

The estimates were prepared on the same general ground rules and assumptions as the GE study. The major design and economic premises are listed in Table 113. The operating conditions for the lime and limestone scrubbers are based on test results at Shawnee. The operating conditions for the magnesia process are essentially the same as reported by McGlamery, et al.[2] with some adjustments made based on the operating experience of Koehler and Burns.[3] The hot air injection reheat used for all processors is based on the Widows Creek limestone process design.

Summaries of the direct investment by process area are shown for the four scrubbing systems in Tables 114 through 117. To obtain the total capital cost (in mid-1975 dollars) of the scrubber system, it is necessary to add indirect construction costs, A&E service costs, and a contingency for expenditures expected though not accounted for. These costs are accounted for in the following manner:

Total direct investment		1.00
Indirect construction costs @ 25%		0.25
	Subtotal	1.25
A&E services @ 15%		0.185
	Subtotal	1.435
Contingency @ 20%		0.287
	Total Capital Cost (mid-1975 dollars)	1.722

The direct capital investment for the four scrubber systems are found in the following tables:

Table 112

SUMMARY OF DIRECT COSTS[a]

SCRUBBING SYSTEM	DIRECT CAPITAL INVESTMENT, $	DIRECT OPERATING COSTS, $/YR.
Lime slurry process with onsite calcination	39,157,000	5,409,700
Lime slurry process without onsite calcination	32,190,000	5,971,000
Limestone slurry process	36,745,000	4,267,500
Magnesia slurry-regeneration process	32,899,000	6,271,900

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a. Basis:
869 MW gross new coal-fired power unit, 3.9% S in fuel; 83% SO_2 removal. Stack gas reheat to 175°F by heated air injection.
Disposal pond (if required) located one mile from power plant.
Pond sized for 30 year operation at 65% capacity.
Cost basis: mid-1975.
Minimum in-process storage; only pumps are spared.

Table 113

GENERAL DESIGN AND ECONOMIC PREMISES FOR TVA ESTIMATE OF WET SCRUBBING SYSTEMS

I. Design Premises

A. The power plant has a gross generating capacity of 869 MW. It has a 30 year life, operating at 0.65 capacity or 5694 hr/yr.

B. Coal composition is the same as ECAS.

C. Flue gas rate and composition are the same as ECAS.

D. Reheat is by heated air injection to reheat flue gas to 175°F.

E. 83% of the SO_2 is to be removed.

F. Bypass ducts are provided. No redundant scrubbers are present.

G. 99% of the particulates are removed with an ESP. The costs for particulate removal and ash handling are not included in this estimate.

H. Chevron vane mist eliminators with intermittent wash are included.

I. Raw material storage is provided for 30 days operation.

J. Onsite untreated ponding of solids wastes is provided.

II. Economic Premises

A. All investment and operating costs are in mid-1975 dollars. Investment costs are scaled to mid-1975 by using Chemical Engineering material and labor indices.

B. Working capital is not considered.

C. Capital charges are at 18%/yr.

III. Additional Design Premises for Wet Lime Scrubbing

A. Four SO_2 absorber units are required.

B. 3 stage TCA type is required.

C. Superficial gas velocity is 12.5 ft/sec.

Table 113 (continued)

D. Total pressure drop is 6" H_2O in the scrubber.

E. Liquid/gas ratio is 50 gal/MSCF.

F. Presaturation spray is 2.5 gal/MSCF.

G. Lime/SO_2 absorbed stoichiometry is 1.05.

H. Absorber hold tank residence time is 10 min.

I. Recycle slurry solids is 8% by weight.

J. Lime makeup slurry solids are 20% by weight.

K. Spent slurry pond solids is 40% by weight.

L. Calcination offgas meets SO_2 emission requirements.

IV. Additional Design Premises for Wet Limestone Scrubbing

A. Four SO_2 absorber units are required.

B. 3 stage TCA type is required.

C. Superficial gas velocity is 12.5 ft/sec.

D. Total pressure drop is 7" H_2O in the scrubber.

E. Liquid/gas ratio is 40 gal/MSCF.

F. Presaturation spray is 2.5 gal/MSCF.

G. Limestone/SO_2 absorbed stoichiometry is 1.50.

H. Absorber hold tank residence time is 10 min.

I. Recycle slurry solids is 10% by weight.

J. Limestone makeup slurry solids are 60% by weight.

K. Spent slurry pond solids is 40% by weight.

Table 113 (continued)

V. Additional Design Premises for Magnesium Oxide Scrubbing

A. Four SO_2 absorber units are provided.

B. One stage venturi is provided.

C. Superficial gas velocity is 75 ft/sec.

D. Total pressure drop is 6" H_2O in the scrubber.

E. Liquid/gas ratio is 20 gal/MSCF.

F. Presaturation spray is 2.5 gal/MSCF.

G. Magnesia/SO_2 absorbed stoichiometry is 1.05.

Table 114 - Lime slurry (onsite calcination)
Table 115 - Lime slurry (offsite calcination)
Table 116 - Limestone slurry
Table 117 - Magnesia slurry (regenerable MgO)

Direct annual operating costs for these systems were estimated and are included in the following tables:

Table 118 - Lime slurry (onsite calcination)
Table 119 - Lime slurry (offsite calcination)
Table 120 - Limestone slurry
Table 121 - Magnesia slurry (regenerable MgO)

To obtain total operating costs, it is necessary to add overhead charges. TVA feels that an appropriate factor for scrubber O&M overhead is 50 percent of total direct costs.

The magnesia slurry process makes a saleable product, 37.5 tons/h of sulfuric acid. To obtain the net revenue required for this process a credit for byproduct sales needs to be considered. A conservative estimate for sales revenue is $25/ton of sulfuric acid. Table 121 does not include any acid sales credit.

The GE cost estimate provides for only 5 years of ponding at a direct cost of $490,000 for an unlined pond. Additional ponds will be required over the life of the plant but provision is not made for them in the GE cost estimate. It is granted that in actual practice disposal ponds may be constructed at intervals as required. However, in comparing alternatives these future expenditures need to be recognized. The TVA estimate does this by providing for a clay-lined disposal pond adequate for 30-year operation at a cost of $7,099,000.

The difference ($4.2 million) between the GE and TVA estimates of direct costs of the lime scrubbing systems, excluding the disposal pond, is concentrated in the scrubbing area costs. This is because the GE design premises specify 8 ft/s superficial gas velocity with six scrubbers, while the TVA design premises specify 12.5 ft/s superficial gas velocity with four scrubbers.

The sludge disposal pond requirement specified in the ECAS report, 39,270 acre ft (1780 acres x 22 ft deep) for 5 years, is excessive. The GE material balance shows a settled used slurry rate of 573 gpm, which corresponds to a settling pond requirement of about 20,000 acre ft. for 5 years. This difference in disposal pond requirements is significant when the cost of disposal ponds and land is considered.

Table 114

LIME SLURRY PROCESS WITH ONSITE CALCINATION
ONSITE UNTREATED POND STORAGE
SUMMARY OF TOTAL DIRECT INVESTMENT[a]

(869 MW gross new coal-fired power unit, 3.9% S in fuel;
83% SO_2 removal)

	Direct investment, $	Percent of direct investment
Materials handling (limestone receiving area, coal receiving area, hoppers, feeders, conveyors, elevators, bins, front-end loader and lime storage bin)	1,242,000	3.17
Limestone calcination (complete rotary kiln including coal grinding, control system, drives, fans, baghouse dust collector, ducting and stack)	6,644,000	16.97
Feed preparation (feeders, conveyors, slakers pumps, tank and agitator)	778,000	1.97
Sulfur dioxide scrubbers (4 mobile bed scrubbers, including feed plenum, pumps, mist eliminators, soot blowers, and tanks)	8,794,000	22.46
Stack gas reheat (4 heated air injection reheaters, fans and ductwork)	1,813,000	4.63
Gas handling (fans, and flue ductwork)	6,786,000	17.33
Calcium solids disposal (onsite disposal pond, clay liner, tank, and pumps)	8,097,000	20.68
Utilities (instrument air generation and supply system, distribution system for process steam, water and electricity)	129,000	0.33
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	1,232,000	3.15
Construction facilities	1,776,000	4.54
Subtotal direct investment excluding land	37,291,000	95.23
Land (622 acres)	1,866,000	4.77
Total direct investment	39,157,000	100.00

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[a] Basis:
869 MW gross new coal-fired power unit, 3.9% S in fuel; 83% SO_2 removal.
Stack gas reheat to 175°F by heated air injection.
Disposal pond located one mile from power plant. Pond sized for 30 yr operation at 65% capacity.
Cost basis: mid-1975.
Minimum in-process storage; only pumps are spared.

Table 115

LIME SLURRY PROCESS
ONSITE UNTREATED POND STORAGE
SUMMARY OF TOTAL DIRECT INVESTMENT[a]

(869 MW gross new coal-fired power unit, 3.9% S in fuel; 83% SO_2 removal)

	Direct investment, $	Percent of direct investment
Materials handling (lime bins, feeders, conveyors, elevators)	1,529,000	4.75
Feed preparation (feeders, conveyors, slakers, pumps, tank and agitator)	778,000	2.42
Sulfur dioxide scrubbers (4 mobile bed scrubbers, including feed plenum, pumps, mist eliminators, soot blowers, and tanks)	8,794,000	27.32
Stack gas reheat (4 heated air injection reheaters, fans and ductwork)	1,813,000	5.63
Gas handling (fans, and flue ductwork)	6,786,000	21.08
Calcium solids disposal (onsite disposal pond, clay liner, tank, and pumps)	8,097,000	25.15
Utilities (instrument air generation and supply system, distribution system for process steam, water and electricity)	118,000	0.37
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	969,000	3.01
Construction facilities	1,458,000	4.53
Subtotal direct investment excluding land	30,342,000	94.26
Land (616 acres)	1,848,000	5.74
Total direct investment	32,190,000	100.00

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a. Basis:
869 MW gross new coal-fired power unit, 3.9% S in fuel; 83% SO_2 removal.
Stack gas reheat to 175°F by heated air injection.
Disposal pond located one mile from power plant. Pond sized for 30 yr operation at 65% capacity.
Cost basis: mid-1975.
Minimum in-process storage; only pumps are spared.

Table 116

LIMESTONE SLURRY PROCESS
ONSITE UNTREATED POND STORAGE
SUMMARY OF TOTAL DIRECT INVESTMENT[a]

(869 MW gross new coal-fired power unit, 3.9% S in fuel; 83% SO_2 removal)

	Direct investment, $	Percent of direct investment
Materials handling (limestone receiving area, hoppers, feeders, conveyors, elevators, and bins)	1,139,000	3.10
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	2,362,000	6.43
Sulfur dioxide scrubbers (4 mobile bed scrubbers, including feed plenum, pumps, mist eliminators, soot blowers, and tanks)	9,140,000	24.87
Stack gas reheat (4 heated air injection reheaters, fans and ductwork)	1,813,000	4.93
Gas handling (fans, and flue ductwork)	6,913,000	18.82
Calcium solids disposal (onsite disposal pond, clay liner, tank, and pumps)	10,156,000	27.64
Utilities (instrument air generation and supply system, distribution system for process steam, water and electricity)	118,000	0.32
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	1,120,000	3.05
Construction facilities	1,638,000	4.46
Subtotal direct investment excluding land	34,399,000	93.62
Land (782 acres)	2,346,000	6.38
Total direct investment	36,745,000	100.00

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a. Basis:

869 MW gross new coal-fired power unit, 3.9% S in fuel; 83% SO_2 removal.
Stack gas reheat to 175°F by heated air injection.
Disposal pond located one mile from power plant. Pond sized for 30 yr operation at 65% capacity.
Cost basis: mid-1975.
Minimum in-process storage; only pumps are spared.

Table 117

MAGNESIA SLURRY--REGENERATION PROCESS
SUMMARY OF TOTAL DIRECT INVESTMENT[a]

(869 MW gross new coal-fired power unit, 3.9% S in fuel;
83% SO_2 removal; 37.5 tons/hr 100% H_2SO_4)

	Direct investment, $	Percent of direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	427,000	1.30
Feed preparation (feeders, conveyors, elevators, tank, agitator and pump)	505,000	1.54
Sulfur dioxide scrubbers (4 venturi scrubbers including feed plenum, pumps, mist eliminators, soot blowers, and tanks)	5,102,000	15.51
Stack gas reheat (4 heated air injection reheaters, fans and ductwork)	1,687,000	5.13
Gas handling (fans, and flue ductwork)	8,276,000	25.15
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators	1,580,000	4.80
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	2,182,000	6.63
Calcining (fluid bed calciner, fans, feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	2,466,000	7.50
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	6,666,000	20.26
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	585,000	1.78
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution system for obtaining process steam, water and electricity from power plant)	472,000	1.43
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	1,350,000	4.10
Construction facilities	1,565,000	4.76
Subtotal direct investment excluding land	32,863,000	99.89
Land (12 acres)	36,000	0.11
Total direct investment	32,899,000	100.00

---

[a] Basis:
869 MW gross new coal-fired power unit, 3.9% S in fuel; 83% SO_2 removal.
Stack gas reheat to 175°F by heated air injection.
Cost basis: mid-1975.
Minimum in-process storage; only pumps are spared.

Table 118

LIME SLURRY PROCESS WITH ONSITE CALCINATION
ONSITE UNTREATED POND STORAGE
AVERAGE ANNUAL DIRECT OPERATING COSTS[a]

(869 MW gross coal-fired power unit, 3.9% S in fuel;
83% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total direct operating cost
Delivered raw material				
Limestone	267.4 M ton	5.00/ton	1,337,000	24.71
Coal	31.3 M ton	21.58/ton	675,500	12.49
Subtotal raw material			2,012,500	37.20
Conversion costs				
Operating labor and supervision	88,570 man-hr	11.75/man-hr	1,040,700	19.24
Utilities				
Process water	282,900 M gal	0.10/M gal	28,300	0.52
Maintenance				
Labor and material - .06 x 37,291,000			2,237,500	41.36
Analyses	6,045 man-hr	15.00/man-hr	90,700	1.68
Subtotal conversion costs			3,397,200	62.80
Total direct costs			5,049,700	100.00

	Dollars/ton coal burned	Mills/kWh[b]	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit direct operating cost	2.51	1.19	11.63	77.49

---

a. Basis:
Life of power plant, 30 yr. at 65% capacity or 5694 hrs/yr.
Coal burned 2,156,550 tons/yr, 9404 Btu/kWh (gross).
Stack gas reheat to 175°F.
Direct investment, $39,157,000.
Investment and operating cost for removal and disposal of fly ash excluded.
Steam required from power plant 112,860 M lb (620°F, 130.3 psig).

b. Net electricity generated:

Steam cycle output		868.6 MW
less: Scrubber	5.9 MW	
ID fan	8.8	
Other (from ECAS Phase II, p. 72)	55.7	
Total auxiliary losses		70.4 MW
Net output		798.2 MW

Table 119

LIME SLURRY PROCESS
ONSITE UNTREATED POND STORAGE
AVERAGE ANNUAL DIRECT OPERATING COSTS[a]

(869 MW gross coal-fired power unit, 3.9% S in fuel;
83% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total direct operating cost
Delivered raw material				
Lime	134.9 M tons	28.00/ton	3,777,200	63.26
Subtotal raw material			3,777,200	63.26
Conversion costs				
Operating labor and supervision	24,210 man-hr	11.75/man-hr	284,500	4.76
Utilities				
Process water	282,900 M gal	0.10/M gal	28,300	0.48
Maintenance				
Labor and material - .06 x 30,342,000			1,820,500	30.49
Analyses	4,030 man-hr	15.00/man-hr	60,500	1.01
Subtotal conversion costs			2,193,800	36.74
Total direct costs			5,971,000	100.00

	Dollars/ton coal burned	Mills/kWh[b]	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit direct operating cost	2.77	1.31	12.83	85.53

---

a. Basis:
Life of power plant, 30 yr. at 65% capacity or 5694 hrs/yr.
Coal burned 2,156,550 tons/yr, 9404 Btu/kWh (gross).
Stack gas reheat to 175°F.
Direct investment, $32,190,000.
Investment and operating cost for removal and disposal of fly ash excluded.
Steam required from power plant 112,860 M lb (620°F, 130.3 psig).

b. Net electricity generated:

Steam cycle output		868.6 MW
less: Scrubber	5.2 MW	
ID fan	8.8	
Other (from ECAS Phase II, p. 72)	55.7	
Total auxiliary losses		69.7 MW
Net output		798.9 MW

Table 120

LIMESTONE SLURRY PROCESS
ONSITE UNTREATED POND STORAGE
AVERAGE ANNUAL DIRECT OPERATING COSTS[a]

(869 MW gross coal-fired power unit, 3.9% S in fuel;
83% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total direct operating cost
Delivered raw material				
Limestone	336.8 M tons	5.00/ton	1,684,000	39.46
Subtotal raw material			1,684,000	39.46
Conversion costs				
Operating labor and supervision	35,040 man-hr	11.75/man-hr	411,700	9.65
Utilities				
Process water	403,200 M gal	0.08/M gal	32,300	0.76
Maintenance				
Labor and material - .06 x 34,399,000			2,063,900	48.36
Analyses	5,040 man-hr	15.00/man-hr	75,600	1.77
Subtotal conversion costs			2,583,500	60.54
Total direct costs			4,267,500	100.00

	Dollars/ton coal burned	Mills/kWh[b]	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit direct operating cost	1.98	0.94	9.17	61.13

---

a. Basis:
Life of power plant, 30 yr. at 65% capacity or 5694 hrs/yr.
Coal burned 2,156,550 tons/yr, 9404 Btu/kWh (gross).
Stack gas reheat to 175°F.
Direct investment, $36,745,000.
Investment and operating cost for removal and disposal of fly ash excluded.
Steam required from power plant 112,860 M lb (620°F, 130.3 psig).

b. Net electricity generated:

Steam cycle output		868.6 MW
less: Scrubber	5.6 MW	
ID fan	9.2	
Other (from ECAS Phase II, p. 72)	55.7	
Total auxiliary losses		70.5 MW
Net output		798.1 MW

Table 121

MAGNESIA SLURRY PROCESS
AVERAGE ANNUAL DIRECT OPERATING COSTS[a]

(869 MW gross coal-fired power unit, 3.9% S in fuel;
83% SO_2 removal; 37.5 tons/hr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total direct operating cost
Delivered raw material				
Magnesium oxide (98%)	2,075 tons	155.00/ton	321,600	5.13
Coke	1,473 tons	23.50/ton	34,600	0.55
Catalyst	4,137 liters	1.65/liter	6,800	0.11
Subtotal raw material			363,000	5.79
Conversion costs				
Operating labor and supervision	39,000 man-hr	11.75/man-hr	458,300	7.31
Utilities				
Fuel oil (No. 6)	10,340 M gal	0.30/M gal	3,102,000	49.46
Process water	4,118,900 M gal	0.05/M gal	205,900	3.28
Maintenance				
Labor and material - .06 x 32,863,000			1,971,800	31.44
Analyses	11,390 man-hr	15.00/man-hr	170,900	2.72
Subtotal conversion costs			5,908,900	94.21
Total direct costs			6,271,900	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh[b]	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit direct operating cost	29.37	2.91	1.38	13.48	89.85

---

a. Basis:
Life of power plant, 30 yr. at 65% capacity or 5694 hrs/yr.
Coal burned 2,156,550 tons/yr, 9404 Btu/kWh (gross).
Stack gas reheat to 175°F.
Direct investment, $32,899,000.
Investment and operating cost for removal and disposal of fly ash excluded.
Steam required from power plant, 967,980 M lb (620°F, 130.3 psig).
Steam credit to power plant, 42,840 lb (366°F, 165 psig).

b. Net electricity generated:

Steam cycle output		868.6 MW
less: Scrubber	8.2	
ID fan	8.8	
Other (from ECAS Phase II, p. 72)	55.7	
Total auxiliary losses		72.7 MW
Net output		795.9 MW

D. ALTERNATIVE DISPOSAL METHODS

Alternative solids disposal methods were considered for the CWS, AFB, and PFB plants. The AFB and PFB plants were designed under ECAS premises which provided only for facilities to haul all solid wastes offsite. The CWS plants costs included a pond for 5-year storage of sludge. To place the three plants on a more comparable basis, capital and O&M costs were examined for alternative methods for 30-year disposal.

Scrubber Sludge

Fling, et al.,[4/] compares three sludge fixation systems: Chemfix, Dravo, and IUCS. In the present study, the Dravo process has been selected for estimating the cost of sludge fixation because Fling reports Chemfix is more expensive and IUCS requires fly ash. The following methods of disposal were considered for cost estimation:

1. Store untreated in clay-lined pond.

   The spent scrubber slurry is pumped to a clay-lined settling pond located one mile from the power plant. The supernatant is recycled to the scrubbing area. It was assumed that the sludge would settle to 40 percent solids.

2a. Store fixed in clay-lined pond.

   Spent slurry is concentrated to about 32-38 percent solids in a thickener, then mixed with a fixing agent. The sludge is then pumped to a settling pond where it settles to about 43 percent solids and cures under water. The supernatant is recycled to the scrubbing area. This design is based on the system that Dravo is installing for Pennsylvania Power Company's Bruce-Mansfield station. The cost per ton of scrubber slurry solids is significantly higher, primarily because the disposal pond is more expensive than damming a ravine.

2b. Fix, store onsite in clay-lined diked impoundment.

   Spent slurry is concentrated to about 32-38 percent solids in a thickener, then mixed with a fixing agent. The sludge is pumped to one of three 30-day capacity settling ponds. The sludge settles to about 40 percent solids and cures in 30 days. The supernatant is drained from the pond and the fixed sludge is dredged and conveyed to a diked impoundment. A collecting basin is included in the diked impoundment to catch any runoff. The fixed sludge is piled to an average depth of 30 ft.

3. Haul offsite, store fixed in clay-lined diked impoundment

   This is similar to the previous case, 2b., except the conveyor is eliminated and instead the fixed solids are trucked offsite to the impoundment.

The cost estimates for these waste disposal systems are shown in Table 122.

Fluidized Bed Combustion Solid Wastes

General Electric[1] states that the fluidized bed combustion solid wastes have the following components:

a. Atmospheric fluidized bed
   42% calcium sulfate
   31% ash
   24% unreacted lime
   3% carbon

b. Pressurized fluidized bed
   42% ash
   26% calcium sulfate
   16% magnesium oxide
   13% unreacted lime
   4% unburned carbon

The costs for disposing of these wastes are not included in the GE study. In making an objective evaluation of fluidized bed combustion the disposal costs must be considered. The following three methods have been identified as viable options in disposing of AFB and PFB wastes:

1. Store untreated in clay-lined pond.

   The solids are slurried and sluiced to a clay-lined pond where the solids are allowed to settle and the supernatant is recycled. The solids as received are water free. When they are slurried, some of the constituents will take on water of hydration. It was assumed that after hydrating, the sludge from the atmospheric fluidized bed process would settle to 45 percent solids and the sludge from the pressurized fluidized bed process would settle to 43 percent solids.

2. Store onsite, treated in clay-lined diked impoundment.

   The solids are transported to the disposal site with a mile-long enclosed conveyor. To fix this material all that is needed is a moderate grind (10 kWh/ton) and addition of water (10 percent by weight). The lime present should cement the solids into a dense concrete-like material. A clay-lined diked impoundment with a collection basin to catch any runoff is included although the need for an impoundment is questionable. The treated solids are piled to an average depth of 30 ft.

3. Haul offsite, store treated in clay-lined diked impoundment.

   This is similar to the previous case except the conveyor is eliminated and instead the solids are trucked offsite to the impoundment.

The cost estimates for these waste disposal systems are shown along with the CWS disposal systems in Table 122.

E. COST OF ELECTRICITY (C.O.E.) BASED ON TVA MODIFICATIONS

The GE study modifications suggested by TVA may be used to calculate the C.O.E. associated with the plant types studied. The C.O.E. for the PFB and AFB plants reflect the increase in capital costs due to uncertainty allowances in equipment estimates and to solids disposal costs. The C.O.E. for different CWS alternatives reflects similar influences with additional sensitivity to the type of wet scrubber used.

The GE study cost estimates included capital and O&M charges for a lime slurry scrubber with onsite calcination. To determine the sensitivity of the CWS plants to the alternative scrubber cases, it is necessary to substitute the TVA scrubber estimates for the costs estimated for the GE scrubber. Table 123 is a calculation breakdown of alternative scrubber costs. Utilization of these results with the TVA modifications previously discussed yield the breakdown as seen in Table 124. The GE plant costs are identical to those presented in the GE study with no TVA modifications. The TVA alternative scrubber estimates shown include TVA modifications to the GE conventional plant and reflect both capital and O&M differences due to the different scrubber types.

The C.O.E. for the AFB and PFB plants includes differences in solids disposal requirements. Table 125 presents calculations for both onsite and offsite disposal costs for the two plant types. The result of these calculations incorporated with estimates discussed in previous sections yields the C.O.E. calculations found in Table 126. Both the GE study estimates and those estimates as modified by TVA include the additional solids disposal requirements to calculate C.O.E. for the AFB and PFB plant types.

Combination of the results found in Tables 123 through 126 yields Table 127. Table 127 gives a C.O.E. breakdown for the plants utilizing both the GE and the TVA estimates. All estimates in Table 127 incorporate solids disposal costs. Changes in the C.O.E. calculated by GE for the CWS, AFB, and PFB are reflected in the capital and O&M requirements, but not in fuel requirements as no change in plant efficiency resulted from TVA modifications.

Cost of Electricity Sensitivity

The costs of electricity presented in Table 127 are based on the guidelines set forth in ECAS. Certain parameters were selected to reflect utility practice. Among these parameters are cost of fuel, fixed charge rate, and capacity factor. The costs of electricity for all power plants are sensitive to changes in these parameters. The cost of fuel was assumed to be \$1.00/10^6Btu. Variations in this parameter directly affect the fuel portion of C.O.E. The capacity factor was set at 65 percent. This is reasonable but actual utility practice may find the capacity factor much different, changing both the O&M and capital portions of C.O.E. The fixed charge rate, set at 18 percent per year, also varies within the utility industry and relates directly to the capital portion of C.O.E.

The C.O.E. for CWS, AFB, and PFB are all affected by the parameter changes mentioned. Representative plant estimates as modified by TVA were

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Table 122

SOLIDS DISPOSAL DIRECT INVESTMENT AND OPERATING COSTS[a]

	Direct investment excluding land, $	Cost of land, $	Annual direct operating costs, $	Dry solids, tons/hr
I. Fluidized bed combustion				
A. Atmospheric fluidized bed combustion				
1. Store untreated in clay-lined pond	14,545,000	3,348,400	983,400	119
2. Store onsite, treated in clay-lined, diked impoundment	3,785,000	1,104,000	1,191,200	119
3. Haul offsite, store treated in clay-lined diked impoundment	2,686,000	1,104,000	1,729,600	119
B. Pressurized fluidized bed combustion				
1. Store untreated in clay-lined pond	17,673,000	4,101,000	1,187,600	154
2. Store onsite treated in clay-lined, diked impoundment	4,612,400	1,425,000	1,524,900	154
3. Haul offsite, store treated in clay-lined, diked impoundment	3,420,000	1,425,000	2,174,500	154
II. Scrubber sludge				
A. Lime wet scrubber				
1. Store untreated in clay-lined pond	8,097,000	1,806,000	564,100	54.6
2.a. Store fixed in clay-lined pond	8,969,000	1,806,000	2,149,400[c]	54.6
b. Fix, store onsite in clay-lined, diked impoundment	5,322,000	1,359,000	2,010,400[c]	54.6
3. Fix, haul offsite, store in clay-lined, diked impoundment	4,364,000	1,359,000	2,294,900[c]	54.6
B. Limestone wet scrubber				
1. Store untreated in clay-lined pond	10,156,000	2,304,000	694,700	74.9
2.a. Store fixed in clay-lined pond	11,156,000	2,304,000	2,840,900[d]	74.9
b. Fix, store, onsite in clay-lined, diked impoundment	6,722,900	1,845,900	2,727,100[d]	74.9
3. Fix, haul offsite, store in clay-lined, diked impoundment	5,694,400	1,845,900	3,131,000[d]	74.9

---

a. Basis:
New coal-fired power unit, onstream time 5694 hr/yr 1975, operating costs.
3.9% S in fuel, SO_2 emitted ≤ 1.2 lb/10^6 Btu heat input.

b. Dry solids composition:

I.A. Atmospheric	I.B. Pressurized	II.A. Lime	II.B. Limestone
42% $CaSO_4$	42% Ash	76% $CaSO_3 \cdot 1/2\ H_2O$	46% $CaSO_3 \cdot 1/2\ H_2O$
31% Ash	26% $CaSO_4$	18% $CaSO_4 \cdot 2\ H_2O$	26% $CaSO_4 \cdot 2\ H_2O$
24% CaO	16% MgO	5% CaO	26% $CaCO_3$
3% C	13% CaO	1% Insolubles	2% Insolubles
	4% C		

c. Included is raw material costing $1,078,800/yr.
d. Included is raw material costing $1,478,700/yr.

Table 123

ALTERNATE SCRUBBER COSTS (EXCLUDING DISPOSAL)

CAPITAL AND O&M COSTS FOR SCRUBBER ALTERNATIVES (NO DISPOSAL COSTS ARE INCLUDED)	LIME WITH ONSITE CALCINATION	LIME WITH OFFSITE CALCINATION	LIMESTONE	MAGNESIA W/REGENERATION
CAPITAL COSTS ($M)				
Direct investment for scrubber(a)	39.16	32.19	36.75	32.90
Less direct investment for disposal(b)	-8.10	-8.10	-10.16	0.00
Less land costs for disposal(b)	-1.81	-1.81	-2.30	0.00
Net scrubber directs	29.25	22.28	24.29	32.90
Indirect field costs @ 25%	7.32	5.57	6.07	8.22
Total direct construction	36.57	27.85	30.36	41.12
A&E @ 15%	5.49	4.18	4.55	6.17
Contingency @ 20%	8.41	6.41	6.98	9.46
Total 1975 1/2 Cost ($M)	50.47	38.44	41.89	56.75
O&M COSTS (MILLS/kWh)				
Direct operating costs	1.19	1.31	0.94	1.38
Direct nonfixed disposal costs	-0.12	-0.12	-0.15	0.00
Net O&M directs	1.07	1.19	0.69	1.38
Overhead @ 50%	0.53	0.59	0.34	0.69
Total O&M	1.60	1.78	1.03	2.07*

*Sale of sulfuric acid would yield additional credit of 1.18 mill/kWh.

(a) From Table 112.
(b) From Table 122.

Table 124

CONVENTIONAL/WET SCRUBBER PLANTS

	GE CWS 250 F/LIME 5 YR. DISPOSAL 8 FT/SEC 747.2 MW	GE CWS 175 F/LIME 5 YR. DISPOSAL 8 FT/SEC 795.5 MW	TVA CWS 175 F/LIME 30 YR. DISPOSAL 12.5 FT/SEC W/CALCINATION	TVA CWS 175 F/LIME 30 YR. DISPOSAL 12.5 FT/SEC OFFSITE CALCINATION	TVA CWS 175 F/LIMESTONE 30 YR. DISPOSAL 12.5 FT/SEC	TVA CWS 175 F/MgO REGENERABLE 12.5 FT/SEC W/H_2SO_4 CREDIT	TVA CWS 175 F/MgO REGENERABLE 12.5 FT/SEC NO H_2SO_4 CREDIT
CAPITAL							
GE (1975)[a]	331.7	334.0					
TVA (1975)[b]			398.03	398.03	398.03	398.03	398.03
GE Scrubber & Disp.[c]	71.6	62.4	-62.40	-62.40	-62.40	-62.40	-62.40
TVA Scrubber[d]			50.47	38.45	41.89	56.75	56.75
TVA Disposal			15.91	15.91	20.18	0.00	0.00
Total 1975	403.3	396.4	402.0	390.0	397.7	392.4	392.4
ESC & I.D.C.	221.0	217.2	220.3	213.7	217.9	215.0	215.0
Total 1980 ($M)	624.3	613.5	622.3	603.7	615.6	607.4	607.4
Cost/kW ($/kW)	835.4	771.3	782.3	758.9	773.9	763.6	736.6
Total Capital $\left(\frac{\text{Mills}}{\text{kWh}}\right)$	26.40	24.38	24.73	23.99	24.47	24.15	24.15
O&M							
GE	2.61	2.45	2.45	2.45	2.45	2.45	2.45
GE Scrubber			-0.97	-0.97	-0.97	-0.97	-0.97
TVA Scrubber			1.60	1.78	1.03	0.89	2.07
TVA Disposal			0.66	0.66	0.90	0.00	0.00
Total O&M $\left(\frac{\text{Mills}}{\text{kWh}}\right)$	2.61	2.45	3.74	3.92	3.41	2.37	3.55
FUEL							
Total FUEL $\left(\frac{\text{Mills}}{\text{kWh}}\right)$	10.10	10.10	10.10	10.10	10.10	10.10	10.10
C.O.E.							
Total C.O.E. $\left(\frac{\text{Mills}}{\text{kWh}}\right)$	39.83	36.93	38.57	38.00	37.99	36.62	37.80

(a) Excludes scrubber and disposal cost.
(b) Includes GE's scrubber and disposal cost.
(c) GE estimate of time scrubber and 5-year disposal cost.
(d) From Table 123.

Table 125

SOLIDS DISPOSAL COSTS FOR FLUIDIZED BED COMBUSTION PLANTS (ADDITIONAL TO GE ESTIMATES)

	AFB		PFB	
	ONSITE	OFFSITE	ONSITE	OFFSITE
CAPITAL COSTS ($M)				
Direct investment	3.78	2.69	4.61	3.42
Indirect field expense @ 90%	3.41	2.42	4.15	3.08
Land	1.10	1.10	1.43	1.42
Total direct construction	8.29	6.21	10.19	7.92
A&E @ 15%	1.24	0.93	1.53	1.19
Contingency @ 20%	1.91	1.43	2.34	1.82
Total 1975 1/2 cost ($M)	11.44	8.57	14.06	10.93
O&M COSTS				
Direct operating costs	0.26	0.37	0.30	0.42
Overheads @ 50%	0.13	0.18	0.15	0.21
Total operating costs $\left(\frac{\text{Mills}}{\text{kWh}}\right)$	0.39	0.55	0.45	0.63

Table 126

FLUIDIZED BED COMBUSTION POWERPLANTS TOTAL COST OF ELECTRICITY (C.O.E.) (INCLUDING SOLIDS DISPOSAL COSTS)	AFB				PFB			
	GE		TVA		GE		TVA	
	ON	OFF	ON	OFF	ON	OFF	ON	OFF
CAPITAL								
Powerplant cost	332.5	332.5	363.1	363.1	421.0	421.0	479.5	479.5
Disposal cost	11.4*	8.6*	11.4	8.6	14.1	10.9	14.1	10.9
Total 1975 cost	343.9	341.1	374.5	371.7	435.1	431.9	493.5	490.4
ESC & I.D.C.	188.5	186.8	205.3	203.3	238.4	236.7	270.4	268.73
Total 1981 cost ($M)	532.4	527.9	579.9	575.0	673.5	668.6	793.9	759.1
Cost/kW ($/kW)	654.0	648.5	712.4	706.4	745.0	739.6	845.1	839.7
Capital C.O.E. $(\frac{\text{Mills}}{\text{kWh}})$	20.67	20.50	22.52	22.33	23.55	23.38	26.72	26.55
O&M								
Plant O&M (GE)	2.22	2.22	2.22	2.22	2.53	2.53	2.53	2.53
Disposal	0.39	0.55	0.39	0.55	0.45	0.63	0.45	0.63
O&M C.O.E. $(\frac{\text{Mills}}{\text{kWh}})$	2.61	2.77	2.61	2.77	2.98	3.16	2.98	3.16
FUEL								
FUEL C.O.E. $(\frac{\text{Mills}}{\text{kWh}})$	9.53	9.53	9.53	9.53	8.71	8.71	8.71	8.71

*From TVA estimates.

Table 127

COMPARISONS OF COSTS CONSIDERING VARIOUS TYPES OF SCRUBBERS AND ALTERNATE METHODS OF WASTE DISPOSAL

	TOTAL CAPITAL $/kW	COST OF ELECTRICITY (Mills/kWh)			
		CAPITAL	O&M	FUEL	TOTAL
Conventional With Scrubber					
GE/CWS/250F/5 yr. disp./lime w/calcination/747 MW	835.4	26.40	2.61	10.73	39.83
GE/CWS/175F/5 yr. disp./lime w/calcination/795 MW	771.3	24.38	2.45	10.10	36.93
TVA/CWS/175/30 yr. disp./lime w/calcination/795 MW	782.3	24.73	3.74	10.10	38.57
TVA/CWS/175F/30 yr. disp./lime (purchased)/795 MW	758.9	23.99	3.92	10.10	38.00
TVA/CWS/175F/30 yr. disp./limestone/795 MW	773.9	24.47	3.41	10.10	37.99
TVA/CWS/175F/MgO/Regenerable/795 MW W/H_2SO_4 credit	728.0	23.01	2.37	10.10	35.48
TVA/CWS/175F/MgO/Regenerable/795 MW NO H_2SO_4 credit	728.0	23.01	3.55	10.1	36.66
Fluidized Bed Power Plants					
GE/AFB/onsite disposal (30 yr.) 814 MW	654.0	20.67	2.61	9.53	32.81
GE/AFB/offsite disposal (30 yr.) 814 MW	648.5	20.50	2.77	9.53	32.80
GE/PFB/onsite disposal (30 yr.) 904 MW	745.0	23.55	2.98	8.71	35.24
GE/PFB/offsite disposal (30 yr.) 904 MW	739.6	23.38	3.16	8.71	35.25
TVA/AFB/uncertainties added/onsite disposal (30 yr.) 814 MW	712.4	22.52	2.61	9.53	34.66
TVA/AFB/uncertainties added/offsite disposal (30 yr.) 814 MW	706.4	22.33	2.77	9.53	34.63
TVA/PFB/uncertainties added/onsite disposal (30 yr.) 904 MW	845.1	26.72	2.98	8.71	38.41
TVA/PFB/uncertainties added/offsite disposal (30 yr.) 904 MW	839.7	26.55	3.16	8.71	38.42
GE/AFB/no disposal/814 MW	632	20.00	9.50	2.20	31.7
GE/PFB/no disposal/904 MW	723	22.90	8.70	2.50	34.1

used to develop the C.O.E. sensitivity plots as seen in Figures 46 through 48. These plants are:

(1) CWS - CWS with TVA modifications
(Lime w/offsite calcination)

(2) AFB - AFB with TVA modifications (including solids disposal)

(3) PFB - PFB with TVA modifications (including solids disposal)

The sensitivity of C.O.E. to cost of fuel is seen in Figure 46. The attractiveness of PFB is seen to increase with rising fuel costs due to its higher efficiency. Figure 47 shows the sensitivity of the three plant types to changes in the fixed charge rate. Here the PFB becomes less attractive with increasing fixed charge rate because of its higher capital cost. Changes in capacity factor affect C.O.E. as shown in Figure 48. Increasing the capacity factor makes the cost of PFB lower relative to the CWS, again reflecting higher PFB efficiency.

In all three plots of C.O.E. sensitivity, the AFB shows lower C.O.E. than the CWS and PFB.

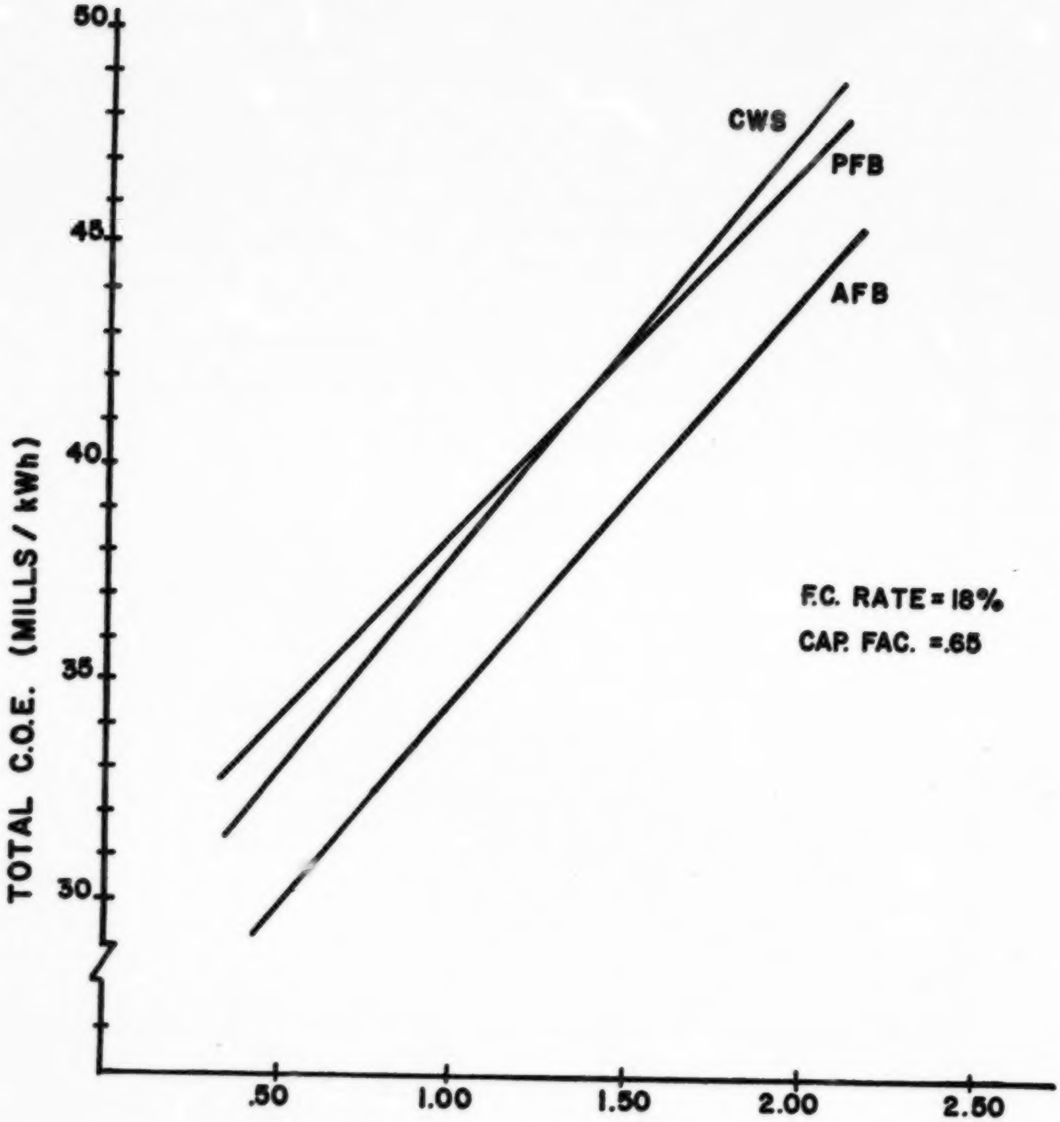

Figure 46. Effect of Fuel Cost on Total Cost of Electricity

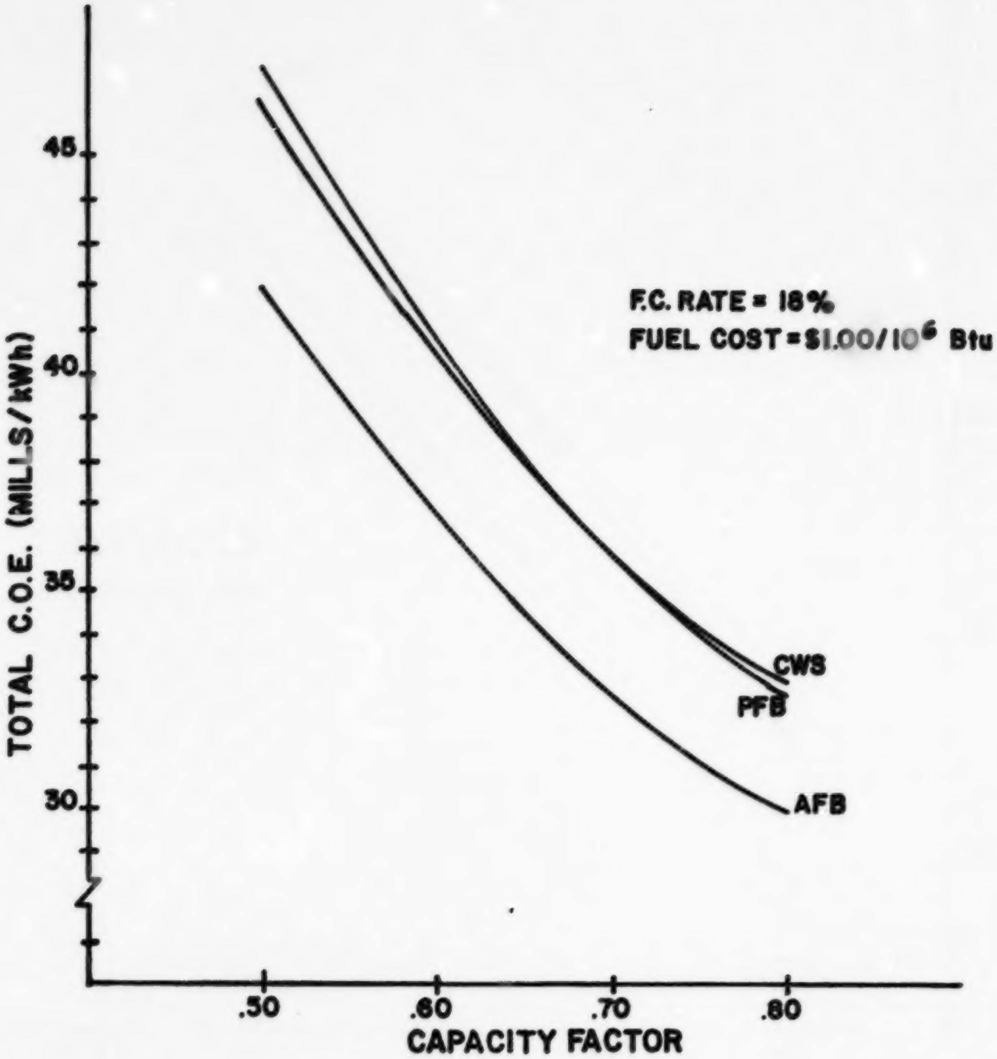

Figure 47. Effect of Capacity Factor on Total Cost of Electricity

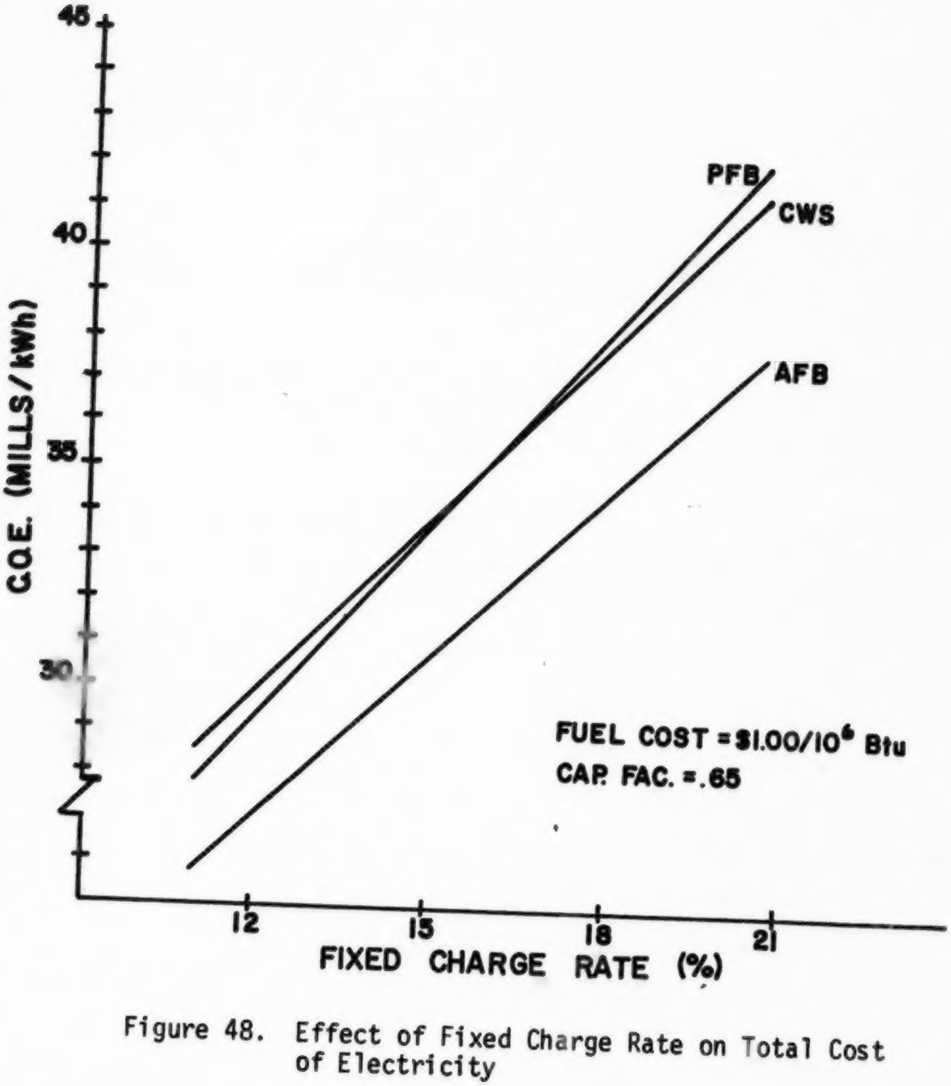

Figure 48. Effect of Fixed Charge Rate on Total Cost of Electricity

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